**BEFORE THE**
**WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

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| **WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,** | ) | |
| **Complainant,** | ) | **DOCKETS UE-170033 and UG-170034 (Consolidated)** |
| **v.** | ) | |
| **PUGET SOUND ENERGY,** | ) | |
| **Respondent.** | ) | |

**RESPONSE TESTIMONY OF ALI AL-JABIR**

**ON BEHALF OF**

**THE FEDERAL EXECUTIVE AGENCIES**

**June 30, 2017**

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**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

**A.** Ali Al-Jabir. My business address is 5151 Flynn Parkway, Suite 412 C/D, Corpus Christi, Texas, 78411.

**Q. WHAT IS YOUR OCCUPATION?**

**A.** I am an energy advisor and a Senior Consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc. ("BAI").

**Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

**A.** These are set forth in Exhibit No. AZA-2.

**Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

**A.** I am appearing on behalf of the Federal Executive Agencies ("FEA"). Our firm is under contract with The United States Department of the Navy ("Navy") to perform cost of service, rate design and related studies. The Navy represents the Department of Defense and all other Federal Executive Agencies in this proceeding. The FEA is one of the largest consumers of electricity in the service territory of Puget Sound Energy ("PSE" or "the Company") and takes electric service from the Company primarily on Schedule 49.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

**A.** My testimony focuses on certain aspects of PSE's proposed electric class cost of service and rate design. Specifically, my testimony addresses the following areas:

- PSE's electric revenue decoupling mechanism ("RDM");
- The classification and allocation of electric generation and transmission fixed costs;
- The allocation of any changes in electric base rate revenues approved in this case; and

- PSE's proposal to implement a formalized, expedited rate filing process.

The fact that I am not addressing other issues in the Company's application in this proceeding should not be construed as an endorsement of the Company's position with regard to such issues.

**Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.**

**A.** My conclusions and recommendations can be summarized as follows:

1. The Commission should reject the continuation of revenue decoupling in this proceeding. Revenue decoupling is an inappropriate and unwarranted departure from traditional ratemaking principles. Revenue decoupling should also be rejected because it would frustrate the voluntary efforts of customers to reduce energy consumption, transfer traditional utility business risks to customers, reduce the Company's motivation to be responsive to the needs of its customers and create unnecessary rate volatility and uncertainty.

2. If the Commission nevertheless determines that it is appropriate to continue PSE's revenue decoupling mechanism, the Commission should restrict RDM only to the revenue impacts resulting from PSE's implementation of energy efficiency programs to achieve mandated conservation targets. In addition, RDM surcharges should be permitted only where there is evidence of a decline in the absolute level of PSE's sales by rate class. Finally, large customers should be excluded from the operation of the electric RDM.

3. If RDM is continued, the Commission should reduce PSE's allowed return on equity to recognize the lower business risks that the Company's shareholders face when revenues are decoupled from sales levels.

4. The Commission should reject PSE's proposal to expand the scope of the electric RDM by moving fixed power costs into the mechanism, as this proposal would significantly increase customer exposure to cost increases associated with decoupling.

5. The Commission should reject the Company's proposal to increase the three percent annual RDM soft cap to five percent for electric customers. Increasing the rate cap in the manner proposed by the Company would harm ratepayers by unduly increasing their exposure to cost increases as a result of RDM. The proposal would also transfer additional business risk away from shareholders and onto customers. Instead, the Commission should transform the 3% annual soft cap into a 3% hard annual cap that would provide a stricter limitation on the exposure of customers to RDM-related cost increases.

6. The Commission should reject PSE's proposal to update the peak credit analysis using more recent proxy generation resource data. The Company's proposal would reduce the demand-related classification of production and transmission fixed costs relative to the settlement agreement from 25 percent to 18 percent. The energy-related classification of these costs would increase from 75 percent to 82 percent. By reducing the demand-related component of production and transmission fixed costs, the Company's proposal to update the peak credit classification assumptions would further deviate from sound, cost-based ratemaking principles.

7. The electric revenue allocation and class rate design should be mainly driven by the goal of achieving cost-based rates.

8. The Company's electric revenue allocation proposal does not show sufficient movement toward cost-based rates and excessively subsidizes residential customers. Moreover, PSE's proposed revenue allocation would inappropriately impose rate increases on customer classes that should receive a rate reduction if cost-based rates were applied.

9. To reduce cross subsidies among rate classes and to create greater movement towards cost-based rates, I recommend that no electric customer class receive a rate increase if it would be entitled to a rate reduction under cost-based rates. This means that Schedules 24, 25, 26 and 46/49 should be maintained at their present rates and should receive no rate increase in this proceeding. In other respects, it is reasonable to maintain the revenue allocation criteria applied by the Company.

10. I recommend that the Commission approve an electric revenue allocation that assigns no base rate increase to Schedules 24, 25, 26 and 46/49. Under this proposal, the revenue shortfall resulting from the modified revenue allocation for Schedules 24, 25, 26 and 46/49 is prorated to the Residential, Primary Voltage and Lighting classes based on the revenue allocation proposed by the Company in order to meet PSE's proposed total electric revenue requirement. Consistent with PSE's proposal, I preserved the linkage in the production and transmission charges between Schedule 40 and Schedule 49 in the revenue allocation. As with the Company's proposal, I also assigned a cost-based revenue increase to the Firm Resale class to bring that class to parity and maintained the Company's proposed base rate increase of 6% for the Choice/Retail Wheeling class.

11. The Commission should reject PSE's proposal to establish a permanent, formal mechanism to process expedited rate filings. The proposed 60 to 90 day timeframe for processing expedited rate filings that the Company proposes would not allow the Commission Staff or impacted parties adequate time to review PSE's application or to engage in meaningful discovery on the Company's proposed revenue requirement. The expedited rate filing process proposed by PSE would fail to adequately protect ratepayers because it would not allow the parties and the

Commission sufficient review time to ensure that excessive or imprudent expenditures are removed from the Company's revenue requirement. Moreover, an expedited rate review process that excludes critical components of a utility's revenue requirement, such as the return on equity, hinders the Commission's ability to set rates that adequately reflect all elements of the utility's cost structure.

12. In order to ensure that rates are just and reasonable and to provide impacted parties with an adequate opportunity to thoroughly vet all components of the Company's costs, the Commission should only allow PSE to adjust its base rates in a full general rate case proceeding.

**Electric Decoupling Mechanism**

**Q. PLEASE SUMMARIZE THE OPERATION OF PSE'S RDM.**

**A.** PSE's RDM links its allowed delivery service revenue to the number of customers it serves. For each decoupling rate group, the Company calculates the allowed delivery revenue as the product of its monthly allowed delivery revenue per customer multiplied by the number of customers served in each month. PSE then defers the difference between its monthly allowed and actual delivery service revenues for each rate group and performs a true-up of these differences in its annual Schedule 142 filing. For the electric RDM, PSE's allowed delivery revenue per customer has grown annually by a "K-factor" of 3%. PSE imposes a Rate Test on its RDM that is designed to ensure that customers will not experience a rate increase of more than 3% annually as a result of the mechanism.[1/]

[1/] Docket Nos. UE-17003 and UG-170034, Prefiled Direct Testimony of Jon A. Piliaris on behalf of Puget Sound Energy, January 13, 2017, pages 107 and 109.

**Q. WHAT IS PSE'S PROPOSAL WITH RESPECT TO THE CONTINUATION OF RDM?**

**A.** The Company proposes that its decoupling mechanisms become permanent and continue until PSE proposes, and the Commission approves, to have them discontinued or modified.[2/]

**Q. SHOULD THE COMMISSION APPROVE THE CONTINUATION OF RDM FOR PSE?**

**A.** No. The Commission should reject the continuation of revenue decoupling in this proceeding. If the Commission allows PSE to continue its RDM, it should only allow recovery of volumetric base revenues that are lost due to the Company's mandated energy efficiency programs.

**Q. AS A MATTER OF POLICY, DO YOU BELIEVE REVENUE DECOUPLING IS WARRANTED FOR PSE?**

**A.** No. Revenue decoupling is an inappropriate and unwarranted departure from traditional ratemaking principles. In addition, revenue decoupling should be rejected because it would:

- Frustrate the voluntary efforts of customers to reduce energy consumption;
- Transfer traditional utility business risks to customers;
- Reduce the Company's motivation to be responsive to the needs of its customers; and
- Create unnecessary rate volatility and uncertainty.

I will elaborate on each of these points in the balance of my direct testimony on this topic.

2/ Ibid, page 146.

**Q. PLEASE EXPLAIN WHY RDM REPRESENTS A DEPARTURE FROM TRADITIONAL RATEMAKING PRINCIPLES.**

**A.** Under the traditional ratemaking process, the Commission establishes the Company's revenue requirement in a base rate case by relying on a snapshot of the Company's costs and revenues for a given test year. The revenue levels are derived using the Company's test year sales levels, adjusted for weather and other known and measurable changes.

Once base rates are set to recover the allowed test year revenue requirement, these rates traditionally remain fixed until the next base rate case. The Company's shareholders bear the risk that earnings could be adversely impacted between base rate cases due to increases in costs or a reduction in revenues. Conversely, the Company's shareholders benefit if PSE can successfully reduce costs or increase revenues between base rate cases. This creates a powerful incentive for the Company's management to operate cost-effectively and to promote economic development in its service area, because economic growth results in increased revenues that improve the Company's bottom line between base rate cases.

Revenue decoupling dramatically alters the traditional ratemaking process by allowing the Company to automatically adjust its base rates outside of a base rate case to reflect the impact of changing sales levels over time. In contrast to the strong economic incentives associated with sales growth that are created by the traditional ratemaking process, full revenue decoupling would essentially make the Company's shareholders indifferent to the impact of fluctuations in sales levels in its service area.

**Q. CAN REVENUE DECOUPLING DISCOURAGE INDEPENDENT CUSTOMER EFFORTS TO PURSUE ENERGY EFFICIENCY?**

**A.** Yes. The irony of revenue decoupling is that it penalizes customers for undertaking successful, voluntary energy efficiency efforts by increasing their distribution charges when their retail consumption levels decline between base rate cases. This result should be rejected because it creates a disincentive for customers to pursue voluntary energy efficiency measures.

**Q. PLEASE EXPLAIN WHY REVENUE DECOUPLING TRANSFERS TRADITIONAL UTILITY BUSINESS RISKS FROM SHAREHOLDERS TO CUSTOMERS.**

**A.** As I discussed above, the traditional base ratemaking process sets a utility's revenue requirement based on the weather-normalized level of test year sales. This approach puts the Company's shareholders at risk for any decline in sales levels between rate cases. This is the case because, all else being equal, a decline in sales translates into reduced revenues relative to the amounts calculated for the test year. Under traditional ratemaking, a decline in sales levels is not recognized in the ratemaking process until the next base rate case.

Revenue decoupling eliminates this traditional business risk by making PSE revenue neutral with respect to fluctuations in sales levels between base rate cases. If sales levels decline between base rate cases, the Company is guaranteed to receive revenues that are based on test year rather on actual sales levels. This approach places customers at risk for rate surcharges due to events that may be entirely outside of their control, such as abnormal weather conditions or a general economic downturn in PSE's service area.

**Q. ARE THE UTILITY'S SHAREHOLDERS COMPENSATED FOR BEARING THE RISK OF FLUCTUATING SALES LEVELS UNDER TRADITIONAL RATEMAKING?**

**A.** Yes. Through the Company's allowed rate of return, the Company's shareholders are compensated for the business risks of operating the utility. Among these risks is the exposure to fluctuations in sales levels between base rate cases due to rising electricity prices, abnormal weather, changing economic conditions or other factors. Absent an adequate downward adjustment to the Company's return on equity to reflect the reduced business risks that revenue decoupling places on PSE, the Company's allowed rate of return would overcompensate the Company's shareholders.

**Q. WHY DOES REVENUE DECOUPLING MAKE THE COMPANY LESS RESPONSIVE TO THE NEEDS OF ITS CUSTOMERS?**

**A.** Revenue decoupling reduces the Company's financial incentive to promote economic development in its service territory. If the Company is financially neutral with respect to the sales volumes for its product, it follows that it would be less focused on providing quality customer service and accommodating the needs of its customers. Moreover, the Company's management would have a reduced impetus to control its operating costs, because PSE would be fully compensated for any decline in sales that resulted from escalating tariff rates.

**Q. PLEASE EXPLAIN HOW REVENUE DECOUPLING CREATES INCREASED RATE VOLATILITY AND UNCERTAINTY RELATIVE TO TRADITIONAL RATEMAKING.**

**A.** RDM calculates the revenue impact of any decline in sales levels and defers these amounts for collection through rate surcharges. Moreover, RDM compensates PSE if sales levels decline for reasons that are unrelated to the implementation of the Company's energy efficiency programs, including an economic recession or abnormal weather. If such events produce a dramatic decline in sales levels between base rate cases, this could result in the accumulation of significant deferrals that would be surcharged to customers in future years. Thus, RDM would expose customers to the risk of significant rate increases, potentially on an annual basis. This contrasts with the situation under traditional ratemaking, in which a retail customer's base rates are fixed between base rate cases.

The rate uncertainty created by RDM proposal would adversely impact customers by exposing them to a significantly higher level of financial risk, making it much more difficult for them to manage their energy budgets and plan for future power requirements.

**Q. HAS THIS RATE VOLATILITY MANIFESTED ITSELF IN PREVIOUS REVENUE DECOUPLING EXPERIMENTS IN WASHINGTON?**

**A.** Yes. Washington experienced problems with rate volatility resulting from the decoupling program it implemented in October 1991 for PSE. The program led to annual rate surcharges in the tens of millions of dollars for each of the five years of program implementation, until the Commission cancelled the program in September 1995.[3/] This experience highlights the significant financial harm that could be produced by RDM and the magnitude of financial risk that the mechanism transfers to ratepayers.

**Q. DOES THE THREE PERCENT RATE INCREASE CAP THAT IS INCLUDED IN RDM FULLY REMEDY THE RATE VOLATILITY CONCERN?**

**A.** No. First, the three percent rate cap simply sets a ceiling on the magnitude of annual RDM-related rate increases. While this cap might limit a customer's maximum

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[3/] Washington Utilities and Transportation Commission, Docket No. UE-950618, Third Supplemental Order, September 21, 1995, pp. 3 – 5.

exposure to rate increases in a given year, RDM rate increases could nevertheless fluctuate from year to year subject to the cap, resulting in continued exposure to rate volatility. More importantly, PSE's rate cap is a "soft cap," meaning that any RDM surcharge amounts not recovered in a given year due to the operation of the cap remain in RDM balancing account and are deferred for recovery in future RDM surcharge filings.[4/] Therefore, PSE's rate cap does not limit a customer's true exposure to rate increases resulting from RDM, but instead spreads the pain of such rate increases over a longer period of time.

**Q. DID PSE SUBMIT AN INDEPENDENT EVALUATION OF THE PERFORMANCE OF ITS DECOUPLING MECHANISMS?**

**A.** Yes. The Company filed a report prepared by H. Gil Peach & Associates, LLC ("Gil Peach") that provides a third-party evaluation of PSE's electric and natural gas decoupling mechanisms.[5/]

**Q. DID THE REPORT FIND THAT THE IMPLEMENTATION OF DECOUPLING SUBSTANTIALLY IMPROVED THE COMPANY'S CONSERVATION PERFORMANCE?**

**A.** No. While the Gil Peach report found that there was continued stability of good performance in PSE's conservation programs, it also concluded that "there is no indication of a sizeable change in electric conservation performance" under decoupling as compared with the time just prior to decoupling.[6/] This finding contradicts the notion that decoupling is required to motivate the Company to undertake conservation efforts.

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4/ Docket Nos. UE-170033 and UG-170034, Prefiled Direct Testimony of Jon A. Piliaris on behalf of Puget Sound Energy, January 13, 2017, page 115.

5/ Docket Nos. UE-170033 and UG-170034, Prefiled Direct Testimony of Jon A. Piliaris on behalf of Puget Sound Energy, January 13, 2017, Exhibit JAP-29.

6/ Gil Peach report at p. 20.

**Q. DID THE REPORT RETURN ANY FINDINGS WITH RESPECT TO THE IMPACT OF WEATHER FLUCTUATIONS ON THE LEVEL OF DECOUPLING DEFERRALS?**

**A.** Yes. With respect to the Residential Natural Gas decoupling group, the Gil Peach report found that cost deferrals in excess of the three percent rate cap were driven by "the nature of the weather."[7/]

**Q. DID THE COMPANY PROVIDE EVIDENCE OF THE MAGNITUDE OF WEATHER RELATED COST DEFERRALS UNDER ITS RDM?**

**A.** Yes. In response to discovery, PSE provided calculations showing that 27% of the electric cost deferrals in calendar year 2016 were due to the impact of weather. For gas customers, the comparable figure is 50%.[8/] This evidence reinforces the concern that decoupling can lead to cost increases for customers that are entirely unrelated to the impact of the Company's energy efficiency programs.

**Q. IF THE COMMISSION ALLOWS CONTINUATION OF RDM DESPITE THE CONCERNS DISCUSSED IN YOUR TESTIMONY, WOULD IT BE APPROPRIATE TO EXCLUDE LARGE CUSTOMERS FROM THE OPERATION OF THE MECHANISM?**

**A.** Yes. The fixed revenue erosion concerns that motivate revenue decoupling proposals may be a relevant concern for residential and small commercial customers due to the fact that PSE recovers its fixed costs from these customers through energy charges. This heightens the risk of fixed revenue erosion resulting from the implementation of energy efficiency programs. By contrast, large customers operate under a rate structure that includes both a demand charge and an energy charge. Therefore, any fixed revenue erosion concerns associated with large customers can be addressed by ensuring that all fixed costs associating with serving large customers are appropriately

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7/ Gil Peach report at p. 25.

8/ Docket Nos. UE-170033 and UG-170034, Puget Sound Energy's Response to WUTC Staff Data Request No. 351, Attachment A.

recovered through demand charges or customer charges, rather than energy charges that fluctuate with energy consumption.

An additional consideration is that many large customers are government agencies or large industrial companies that already have government mandates or strong economic incentives to pursue independent energy efficiency efforts.

Based on the foregoing considerations, it is inappropriate to include PSE's large customers in RDM.

**Q. IN THE EVENT THE COMMISSION DECIDES TO CONTINUE RDM MECHANISM FOR PSE DESPITE THE CONCERNS YOU HAVE RAISED, WOULD IT BE APPROPRIATE TO LIMIT THE OPERATION OF RDM TO SALES REDUCTIONS THAT ARE DRIVEN ONLY BY PSE'S MANDATED ENERGY EFFICIENCY PROGRAMS?**

**A.** Yes. In the event that the Commission approves the continuation of PSE's RDM despite the objections set forth in my testimony, it would be reasonable to restrict the operation of the mechanism such that RDM surcharges are designed to compensate PSE only for sales declines that are a direct result of energy efficiency programs implemented to achieve conservation targets mandated by the Commission. This approach would ensure that customers are protected from rate increases associated with sales declines that may result from other factors such as weather fluctuations or a general economic downturn in the Company's service area.

However, even under this approach, RDM surcharges should be authorized only in the event that PSE's sales levels, by rate group, decline in absolute terms relative to the sales levels used to establish rates in the Company's most recent base rate case. If economic growth in PSE's service area or other exogenous factors yield an increase in sales volumes that more than offsets any sales reductions resulting from the implementation of energy efficiency programs, the Company will not suffer any economic harm and therefore no RDM surcharge would be justified under these circumstances. In other words, RDM should consider the broader pattern of PSE's sales levels and avoid a narrow focus only on sales reductions related to energy efficiency programs.

Moreover, RDM surcharges should be limited to independently verified sales reductions that directly result from the implementation of energy efficiency programs that are required to meet PSE's conservation targets, as approved by the Commission. Any incremental sales reductions that result from voluntary customer efforts to reduce load or from any other factors should be excluded from RDM. It would clearly be unreasonable to approve special ratemaking treatment in the form of revenue decoupling to immunize the Company from the revenue impact of purely voluntary energy efficiency efforts undertaken either by the Company itself or by its customers.

**Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS IN THE EVENT THE COMMISSION CONTINUES PSE'S RDM?**

**A.** Yes. If the Commission approves the continuation of RDM, the resultant lowering of PSE's business risk profile should translate into a reduction in the authorized return on equity that the Commission approves in this proceeding.

**Q. HAVE OTHER STATE REGULATORY COMMISSIONS RECOGNIZED THAT A DOWNWARD ADJUSTMENT TO A UTILITY'S RETURN ON EQUITY IS APPROPRIATE IF REVENUE DECOUPLING OR SIMILAR POLICIES ARE IMPLEMENTED?**

**A.** Yes. The Connecticut Department of Public Utility Control issued an order which found that the implementation of a revenue decoupling proposal permitted the

Department to lower the allowed return on equity for United Illuminating Company.[9] Moreover, the Missouri Public Service Commission applied an explicit reduction to the allowed return on equity of Missouri Gas Energy to recognize the reduced risks associated with the adoption of a straight-fixed variable rate design, which is an alternative approach to achieving the results sought by PSE through RDM.[10] Finally, the Indiana Utility Regulatory Commission issued an Order that stated the following on this issue:

> "Further, we agree with the OUCC's comments that decoupling mechanisms clearly shift risk from the utility to ratepayers, and that reduction of risk should be considered in determining the appropriate return on equity of for-profit gas utilities." (Indiana Utility Regulatory Commission, Order, Cause No. 43180, Issued October 21, 2009, page 10)

**Q. IF THE COMMISSION CONTINUES REVENUE DECOUPLING FOR PSE, SHOULD IT ALSO LIMIT THE NUMBER OF OTHER RATE ADJUSTMENT MECHANISMS THAT THE COMPANY CAN APPLY?**

**A.** Yes. Rate adjustment mechanisms increase financial risk and rate volatility for customers by giving the Company additional avenues to increase customer rates between base rate cases. Thus, additional adjustment mechanisms would only heighten the already high level of risk that is imposed on customers via RDM. Therefore, it is vital to control the proliferation of other rate mechanisms that could impose additional rate surcharges on the Company's customers outside of a base rate case.

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[9] Connecticut Department of Public Utility Control, Docket No. 08-07-04, *Application of the United Illuminating Company to Increase its Rates and Charges*, Decision, February 4, 2009, page 123.

[10] Missouri Public Service Commission, Case No. GR-2006-0422, *In the Matter of Missouri Gas Energy's Tariffs Increasing Rates for Gas Service Provided to Customers in the Company's Missouri Service Area*, Report and Order, March 22, 2007, page 31.

**Q. IF THE COMMISSION CONTINUES REVENUE DECOUPLING, SHOULD IT MAKE RDM PERMANENT AS PROPOSED BY PSE?**

**A.** No. If the Commission continues RDM, it should only continue the mechanism for a fixed period of time (e.g., three years) to allow for further review of the mechanism's performance at the end of the renewal period. This approach would ensure that the Commission will revisit the operation of the mechanism by a date certain.

**Q. IS PSE PROPOSING TO EXPAND THE SCOPE OF ITS ELECTRIC DECOUPLING MECHANISM?**

**A.** Yes. The Company proposes to significantly expand the scope of the electric RDM by moving fixed power costs into the mechanism, in addition to delivery costs.[11/]

**Q. WHAT IS DRIVING THIS PROPOSAL TO EXPAND THE SCOPE OF THE ELECTRIC RDM?**

**A.** The Company states that this proposal results from the settlement stipulation approved in Docket No. UE-130617.

**Q. DOES THE SETTLEMENT AGREEMENT IN THAT DOCKET REQUIRE THE COMMISSION TO EXPAND THE SCOPE OF THE ELECTRIC RDM TO INCLUDE FIXED POWER COSTS?**

**A.** No. The settlement agreement only requires fixed power costs to be moved into the electric decoupling mechanism if the Commission decides to continue RDM in this general rate case.

**Q. IS IT APPROPRIATE TO EXPAND THE ELECTRIC RDM IN THE MANNER PROPOSED BY PSE?**

**A.** No. Significantly expanding the costs subject to the decoupling mechanism would increase customer exposure to cost increases and deferrals associated with decoupling, particularly in light of the fact that the three percent annual rate cap on decoupling cost

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11/ Docket Nos. UE-170033 and UG-170034, Prefiled Direct Testimony of Jon A. Piliaris on behalf of Puget Sound Energy, January 13, 2017, page 127.

increases is a soft cap that allows increases in excess of the cap to be deferred for recovery in future years. This proposal would also further insulate the Company's shareholders from the risk of revenue fluctuations, to the detriment of ratepayers. For these reasons, the Commission should reject PSE's proposal to include fixed power costs in its electric RDM.

**Q. IS PSE PROPOSING TO MODIFY THE ANNUAL RATE CAP FOR ELECTRIC CUSTOMERS UNDER RDM RATE TEST?**

**A.** Yes. The Company proposes to increase the rate cap for all electric customers subject to RDM from three percent to five percent.[12/] The Company contends that it is appropriate to increase the electric rate cap to address the potential impact of expanding the scope of the electric RDM to include fixed power costs.

**Q IS IT REASONABLE TO INCREASE THE RATE CAP IN THE MANNER PROPOSED BY THE COMPANY?**

**A.** No. Increasing the rate cap would harm ratepayers by unduly increasing their exposure to cost increases as a result of RDM. The proposal would also transfer additional business risk away from shareholders and onto customers. Therefore, the Commission should reject PSE's proposal to increase the electric rate cap for electric customers.

**Q. IS AN INCREASE IN THE RATE CAP JUSTIFIED BY THE EXPANSION OF THE ELECTRIC RDM TO INCLUDE FIXED POWER COSTS?**

**A.** No. If this concern is a central driver for PSE's proposal, it would be better to keep fixed power costs out of the mechanism in order to limit customer exposure to unpredictable and potentially large RDM rate increases.

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[12/] Docket Nos. UE-170033 and UG-170034, Prefiled Direct Testimony of Jon A. Piliaris on behalf of Puget Sound Energy, January 13, 2017, page 5.

**Q. IS THE COMPANY'S PROPOSAL TO INCREASE THE ELECTRIC RDM RATE CAP SUPPORTED BY THE FINDINGS OF THE GIL PEACH REPORT?**

**A.** No. In fact, the Gil Peach report concluded that the three percent rate cap has worked well for the electric decoupling groups and should be continued.[13]

**Q. IF CONTINUATION OF DECOUPLING IS ALLOWED, DO YOU HAVE ANY RECOMMENDATIONS WITH RESPECT TO THE OPERATION OF THE RATE CAP?**

**A.** Yes. To reduce the risk of large, cumulative cost deferrals, the Commission should transform the three percent soft cap into a hard, annual three percent rate cap. Under this approach, the Company's shareholders would bear the risk of any revenue shortfalls in excess of the three percent annual hard cap. This approach would provide added protection to ratepayers from RDM rate increases and would provide a more balanced allocation of the risks associated with revenue fluctuations relative to the current three percent soft cap.

**Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS WITH RESPECT TO THE REVENUE DECOUPLING PROPOSAL SUBMITTED BY PSE IN THIS CASE.**

**A.** The Commission should reject PSE's proposal to continue RDM. Revenue decoupling should be rejected because it unjustifiably departs from traditional ratemaking principles, frustrates voluntary conservation efforts, transfers business risks to customers, makes the Company less responsive to customer needs and increases rate volatility and uncertainty.

If the Commission nevertheless determines that it is reasonable to continue RDM, the Commission should restrict RDM only to the revenue impacts resulting from PSE's implementation of energy efficiency programs to achieve mandated

[13] Gil Peach report at page 15.

conservation targets. In addition, RDM surcharges should be permitted only where there is evidence of a decline in the absolute level of PSE's sales by rate group. Furthermore, the mechanism should exclude the revenue impact of voluntary customer efforts to reduce load and the impact of any voluntary Company expansion of its energy efficiency programs beyond the levels required by the Commission.

If RDM is continued, the Commission should also reduce PSE's allowed return on equity to recognize the lower business risks that the Company's shareholders face when revenues are decoupled from sales levels. The Commission should also reject PSE's proposal to expand the scope of the electric RDM by moving fixed power costs into the mechanism.

Finally, the Commission should reject the Company's proposal to increase the three percent annual RDM soft cap to five percent for electric customers. Instead, the Commission should transform the 3% annual soft cap into a hard cap that would provide a stricter limitation on the exposure of customers to RDM-related cost increases.

**<u>Classification & Allocation of Generation & Transmission Fixed Costs</u>**

**Q. PLEASE COMMENT ON THE BASIC PURPOSE OF A CLASS COST OF SERVICE STUDY ("CCOSS").**

**A.** After determining the total Company cost of service or revenue requirement, a CCOSS is used to allocate the revenue requirement or cost responsibility among the customer classes. A CCOSS compares the cost that each customer class imposes on the system to the revenues each class contributes. For example, when a customer class produces the same rate of return as the total system rate of return, it is paying revenue to the utility just sufficient to cover the costs incurred in serving that class. If a class produces a below-average rate of return, it may be concluded that the revenues provided by the class are insufficient to cover all relevant costs to serve that class. On the other hand, if a class produces a rate of return above the system average, it is not only paying revenues sufficient to cover the cost attributable to it, but in addition, it is paying part of the cost attributable to other classes who produce a below system average rate of return. The CCOSS shows the cost to serve each rate class reflecting cost causation, as well as the rate of return from each class under current and proposed rates.

**Q. HOW IS THE COST OF SERVING EACH CUSTOMER CLASS DETERMINED?**

**A.** The appropriate mechanism to determine the cost of serving each customer class is a fully allocated embedded CCOSS. It follows, however, that the objective of cost-based rates cannot be attained unless the CCOSS is developed using cost-causation principles.

**Q. WHY IS A CCOSS OF IMPORTANCE?**

**A.** A CCOSS shows the costs that a utility incurs to serve each customer class. It is a widely held principle that costs should be allocated among customer classes on the basis of cost-causation. The tenet that costs that cannot be directly assigned to a particular class should be allocated based on cost causation is perhaps the most universally accepted cost of service principle. The costs should be allocated to the classes on the basis of how or why those costs are incurred by the utility. The results of a CCOSS are used in assigning cost responsibilities to various customer classes in regulatory proceedings.

**Q. SHOULD THE COST ALLOCATION AND RATE DESIGN PROCESS FOLLOW COST-CAUSATION PRINCIPLES?**

**A.** Yes. Rates that are based on consistently applied cost-causation principles are not only fair and reasonable, but further the cause of stability, conservation and efficiency. When consumers are presented with price signals that convey the consequences of their consumption decisions, i.e., how much energy to consume, at what rate, and when, they tend to take actions which not only minimize their own costs, but those of the utility as well.

Although factors such as simplicity, gradualism, economic development and ease of administration may also be taken into consideration when determining the final spread of the revenue requirement among classes, the fundamental starting point and guideline should be the cost of serving each customer class produced by the CCOSS.

**Q. PLEASE DESCRIBE THE PROPER FUNDAMENTALS OF A CCOSS.**

**A.** Cost of service is a basic and fundamental ingredient in the ratemaking process. In all cost of service studies, certain fundamental concepts should be recognized. Of primary importance among these concepts is the cost-causation principle.

The first step in a CCOSS is known as <u>functionalization</u>. This simply refers to the process by which the Company's investments and expenses are reviewed and put into different categories of cost. The primary functions utilized are production, transmission and distribution. Of course, each broad function may have several subcategories to provide for a more refined determination of cost of service.

The second major step is known as <u>classification</u>. In the classification step, the functionalized costs are separated into the categories of demand-related, energy-related and customer-related costs in order to facilitate the allocation of costs applying the cost-causation principles.

Demand- or capacity-related costs are those costs that are incurred by the utility to serve the amount of demand that each customer class places on the system. A traditional example of capacity-related costs is the investment associated with generating stations, transmission lines and a portion of the distribution system. Once the utility makes an investment in these facilities, the costs continue to be incurred, irrespective of the number of kilowatthours generated and sold or the number of customers taking service from the utility.

Energy-related costs are those costs that are incurred by the utility to provide the energy required by its customers. For example, fuel expense is almost directly proportional to the amount of kilowatthours supplied by the utility system to meet its customers' energy requirements. It should be noted that none of a utility's distribution costs are energy-related.

Customer-related costs are those costs that are incurred to connect customers to the system and are independent of the customer's demand and energy requirements. Primary examples of customer-related costs are investments in meters, services and the portion of the distribution system that is necessary to connect customers to the system. In addition, such accounting functions as meter reading, bill preparation and revenue accounting are considered customer-related costs.

The final step in the CCOSS is the allocation of each category of the functionalized and classified costs to the various customer classes using cost-causation principles. Demand-related costs are allocated on a basis that gives recognition to each class's responsibility for the Company's need to build new assets to serve demands imposed on the system. Energy-related costs are allocated on the basis of energy use by each customer class. Customer-related costs are allocated based upon the number of customers in each class, weighted to account for the complexity of servicing the needs of the different classes of customers.

**Q. WHY IS IT IMPORTANT TO ADHERE TO BASIC COST OF SERVICE PRINCIPLES IN THE REVENUE ALLOCATION AND RATE DESIGN PROCESS?**

**A.** The basic reasons for using cost of service as the primary factor in the revenue allocation/rate design process are equity, cost causation, appropriate price signals, conservation and revenue stability.

**Q. HOW IS THE EQUITY PRINCIPLE ACHIEVED BY BASING RATES ON COSTS?**

**A.** To the extent practical, when rates are based on cost, each customer pays what it costs the utility to serve them, no more and no less. If rates are not based on cost of service, then some customers contribute disproportionately to the utility's revenue requirement and provide contributions to the cost to serve other customers. This is inherently inequitable.

**Q. HOW DO COST-BASED RATES PROVIDE APPROPRIATE PRICE SIGNALS TO CUSTOMERS?**

**A.** Rate design is the step that follows the allocation of costs to classes, so it is important that the proper amounts and types of costs be allocated to the customer classes so that they may ultimately be reflected in the rates.

When the rates are designed so that the energy costs, demand costs, and customer costs are properly reflected in the energy, demand and customer components of the rate schedules, respectively, customers are provided with the proper incentives to manage their loads appropriately. This, in turn, provides the correct signal to the utility about the need for new investment. When customers impose a certain level of demand on the system, they should pay for the prudent cost that the utility incurs to supply that demand and the energy charge that they pay should reflect the cost of providing that energy.

From a rate design perspective, overpricing the energy portion of the rate and underpricing the fixed components of the rate, such as customer and demand charges, will result in a disproportionate share of revenues being collected from high energy consuming or high load factor customers and send erroneous price signals to all customers.

**Q. HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?**

**A.** Conservation occurs when wasteful or inefficient uses of electricity are discouraged or minimized. Only when rates are based on actual costs do customers receive an accurate and appropriate price signal against which to make their consumption decisions. If rates are not based on costs, then customers may be induced to use electricity inefficiently in response to the distorted price signals.

**Q. PLEASE DISCUSS THE REVENUE STABILITY CONSIDERATION.**

**A.** When rates are closely tied to costs, the impact on the utility's earnings due to changes in customer use patterns will be minimized. Rates that are designed to track changes in the level of costs result in revenue changes that mirror cost changes. Thus, cost-based rates provide an important enhancement to a utility's earnings stability, reducing its need to file for rate increases.

From the perspective of the customer, cost-based rates provide a more reliable means of determining future levels of power costs. If rates are based on factors other than the cost to serve, it becomes much more difficult for customers to translate expected utility-wide cost changes, such as expected increases in overall revenue requirements, into changes in the rates charged to particular customer classes and to customers within the class. This situation reduces the attractiveness of expansion, as well as continued operations, in the utility's service territory because of the limited ability to plan and budget for future power costs.

**Q. WHAT METHOD DID PSE USE TO CLASSIFY AND ALLOCATE FIXED PRODUCTION AND TRANSMISSION COSTS IN ITS ELECTRIC CCOSS TO THE CUSTOMER CLASSES?**

**A.** PSE used the peak credit methodology to divide production costs into demand and energy components based on the ratio of the cost of a proxy peaking generating resource to the cost of a proxy base load generating resource. The demand-related component of fixed production and transmission costs was allocated to the classes using a 4CP allocation factor, which is based on each class's contribution to the Company's system peak demand during the months of November and December 2015 and January and February 2016. PSE allocated the energy-related component of fixed production and transmission costs based on class energy consumption.

**Q. WHAT SPECIFIC CLASSIFICATION OF FIXED PRODUCTION AND TRANSMISSION COSTS DID THE COMPANY USE IN ITS ELECTRIC CCOSS?**

**A.** PSE classified 25 percent of fixed production and transmission costs as demand-related and 75 percent as energy-related.

**Q. WHAT IS THE BASIS FOR THE COMPANY'S CLASSIFICATION PROPOSAL?**

**A.** PSE bases its cost classification proposal on the rate design settlement in Docket No. UE-141368. Paragraph 10 of that settlement agreement specifies that, in the Company's next general rate case, "PSE will adjust demand/energy cost allocation percentages to 25% demand and 75% energy."

**Q. CAN PSE'S ELECTRIC CCOSS BE USED AS A REASONABLE REFERENCE POINT FOR ESTABLISHING EACH CLASS'S REVENUE RESPONSIBILITY?**

**A.** Yes, in light of Commission precedent and the settlement agreement in Docket No. UE-141368, I believe it is reasonable to rely on the Company's electric CCOSS study to establish the customer class revenue responsibility for the purposes of this case.

**Q. PSE ASSERTS THAT IT WOULD BE MORE APPROPRIATE TO UPDATE THE PEAK CREDIT ANALYSIS USING MORE RECENT PROXY GENERATION RESOURCE DATA. WHAT IMPACT WOULD UPDATING THE PEAK CREDIT ANALYSIS HAVE ON THE COST CLASSIFICATION PERCENTAGES?**

**A.** Based on the Company's calculations, PSE's proposal to update the peak credit analysis would reduce the demand-related classification of production and transmission fixed costs relative to the settlement agreement from 25 percent to 18 percent. The energy-related classification of these costs would increase from 75 percent to 82 percent.[14/] PSE asserts that this modification would be consistent with the intent of the settlement agreement.

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14/ Docket Nos. UE-170033 and UG-170034, Prefiled Direct Testimony of Jon A. Piliaris on behalf of Puget Sound Energy, January 13, 2017, page 29.

**Q. WOULD IT BE APPROPRIATE TO MODIFY THE CLASSIFICATION PERCENTAGES IN THE MANNER PROPOSED BY THE COMPANY?**

**A.** No. As noted above, paragraph 10 of the settlement agreement explicitly requires that the demand and energy classification percentages be set at 25 percent demand and 75 percent energy in this proceeding.

By reducing the demand-related component of production and transmission fixed costs, the Company's proposal to update the peak credit classification assumptions would further deviate from sound, cost-based ratemaking principles that require all such costs to be classified as demand-related.

The Commission should reject PSE's proposal to update the peak credit classification assumptions and modify the demand and energy classification percentages specified in the agreement.

**<u>Electric Revenue Allocation</u>**

**Q. WHAT SHOULD BE THE PRINCIPAL CONSIDERATION IN DEVELOPING THE REVENUE ALLOCATION AND CLASS RATE DESIGN IN THIS PROCEEDING?**

**A.** For the reasons described earlier in my direct testimony, the revenue allocation and class rate design should be mainly driven by the goal of achieving cost-based rates.

**Q. HAVE YOU REVIEWED THE RESULTS OF THE COMPANY'S ELECTRIC CCOSS?**

**A.** Yes. The results of the CCOSS are summarized in Exhibit No. AZA-3. This exhibit shows the CCOSS results at present and proposed rates under the Company's cost study. The CCOSS results include the rate of return, the relative rate of return index, and the revenue under- or over-collection.

**Q. HOW CAN THE CCOSS RESULTS BE INTERPRETED WITH RESPECT TO THE REVENUE CONTRIBUTION OF EACH CLASS RELATIVE TO ITS COST OF SERVICE?**

**A.** The rates of a customer class are set at cost of service when the relative rate of return index of the class is 100. At that level, the rate of return derived from the class is equal to the system rate of return. A customer class has a revenue under-collection when the revenues provided through its rates are less than the cost to serve that class, resulting in a class relative rate of return index below 100. Conversely, a customer class has a revenue over-collection when the revenues collected from the class are greater than the cost to serve that class, resulting in a relative rate of return index greater than 100.

**Q. HOW DOES THE COMPANY PROPOSE TO DISTRIBUTE THE PROPOSED ELECTRIC REVENUE INCREASE AMONG THE CUSTOMER CLASSES?**

**A.** Exhibit No. AZA-4 shows the Company's proposed revenue increase by amount and as a percentage of present revenue for each customer class. For comparison purposes, the exhibit also shows the rate increases that would result from a direct application of the results of the CCOSS in this proceeding.

**Q. WHAT CRITERIA DID THE COMPANY APPLY TO DISTRIBUTE THE PROPOSED ELECTRIC REVENUE INCREASE IN THIS PROCEEDING AMONG THE CUSTOMER CLASSES?**

**A.** With limited exceptions, PSE generally proposes to apply an adjusted system average rate increase to retail customer classes that are within five percent of full parity. Rate classes that are more than five percent above full parity would receive a rate increase that is 75 percent of the adjusted average increase. The adjusted average rate increase calculated by the Company accounts for the effect of above-average and below-average increases to certain classes.

For Schedule 40, the Company linked the production and transmission charges to the High Voltage schedules, while developing the distribution charges based on customer-specific information. This results in a calculated revenue allocation amount for Schedule 40.[15/]

**Q. HOW DOES THE COMPANY'S REVENUE ALLOCATION PROPOSAL COMPARE TO THE ACTUAL COST TO SERVE THE RATE CLASSES, AS INDICATED BY THE CCOSS RESULTS?**

**A.** The major impact of the revenue allocation proposal is to reduce the rate increase for the residential rate class significantly below the cost-based level. As shown on line 1 of Exhibit No. AZA-3, the Company proposes a base rate revenue subsidy of $80.9 million for the residential class. This subsidy is financed by several other rate classes on PSE's system, including Schedule 49, through rates that exceed their fully allocated class cost of service.

The other significant impact of the Company's revenue allocation proposal is that it would impose a rate increase on several rate classes that should receive a rate reduction under cost-based rates. This result is shown in Exhibit No. AZA-4. For example, line 7 of Exhibit No. AZA-4 shows that the High Voltage class (Schedules 46/49) should receive a 1.4% rate reduction to bring its rates in line with cost of service. However, under the Company's proposal, this class would receive a 6.1% rate increase. This same phenomenon can be observed for each of the three secondary voltage level classes (Schedules 24, 25, and 26).

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[15/] Docket Nos. UE-170033 and UG-170034, Prefiled Direct Testimony of Jon A. Piliaris on behalf of Puget Sound Energy, January 13, 2017, pages 53 - 54.

**Q. IS THE COMPANY'S ELECTRIC REVENUE ALLOCATION PROPOSAL REASONABLE IN YOUR OPINION?**

**A.** No. The Company's proposal does not show sufficient movement toward cost-based rates and excessively subsidizes residential customers. Moreover, it is inappropriate to impose rate increases on customer classes that should receive a rate reduction if cost-based rates were applied.

**Q. ARE YOU PROPOSING ANY MODIFICATIONS TO THE COMPANY'S ELECTRIC REVENUE ALLOCATION PROPOSAL?**

**A.** Yes. To reduce cross subsidies among the rate classes and to create greater movement towards cost-based rates, I recommend that no class receive a rate increase if it would be entitled to a rate reduction under cost-based rates. This means that Schedules 24, 25, 26 and 46/49 should be maintained at their present rates and should receive no rate increase in this proceeding. In other respects, it is reasonable to maintain the revenue allocation criteria applied by the Company.

**Q. HAVE YOU PREPARED A MODIFIED ELECTRIC REVENUE ALLOCATION THAT REFLECTS YOUR RECOMMENDATION?**

**A.** Yes. Exhibit No. AZA-5, columns (4) and (5) shows my recommended revenue allocation. As can be seen in the exhibit, my recommended revenue allocation imposes no rate increase on customer classes that should receive a rate reduction under cost-based rates (Schedules 24, 25, 26 and 46/49). Under my proposal, the revenue shortfall resulting from my modified revenue allocation for Schedules 24, 25, 26 and 46/49 is prorated to the Residential, Primary Voltage and Lighting classes based on the revenue allocation proposed by the Company in order to meet PSE's proposed total electric revenue requirement. Consistent with PSE's proposal, I preserved the linkage in the production and transmission charges between Schedule 40 and Schedule

49 in the revenue allocation. This has the effect of reducing the rate increase for Schedule 40 relative to the Company's proposal. I also tracked PSE's proposal by assigning a cost-based revenue increase to the Firm Resale class to bring that class to parity and by maintaining the Company's proposed base rate increase of 6% for the Choice/Retail Wheeling class.

**Expedited Rate Filing Process**

**Q. PLEASE SUMMARIZE PSE'S EXPEDITED RATE FILING PROPOSAL IN THIS PROCEEDING.**

**A.** PSE asks the Commission to establish formal procedures that would authorize the Company to process rate filings on an expedited basis. Under these procedures, the Company requests that expedited rate filings be processed within an extremely condensed timeframe of 60 to 90 days.

As the Company describes it, an expedited rate filing would allow PSE to update all of its costs with the exception of power and purchased gas costs. The expedited filing would not include any changes in the Company's rate spread, rate design or rate of return relative to the most recent general rate case. The only allowed adjustments to the cost of capital would be to update debt costs for known changes.[16/]

**Q. HAS THE COMMISSION PREVIOUSLY APPROVED AN EXPEDITED RATE FILING FOR PSE?**

**A.** Yes. The Commission approved PSE's expedited rate filing in 2013 in Docket Nos. UE-130137 and UG-130138. At that time, the Commission indicated that the expedited rate filing was a one-time mechanism. The Company now seeks to transform this one-time authorization into a formal, permanent mechanism.

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[16/] Docket Nos. UE-170033 and UG-170034, Prefiled Direct Testimony of Katherine J. Barnard on behalf of Puget Sound Energy, January 13, 2017, pages 68 - 72.

**Q. IS IT REASONABLE TO ESTABLISH A PERMANENT, FORMAL MECHANISM TO PROCESS EXPEDITED RATE FILINGS?**

**A.** No. The extremely compressed 60 to 90 day timeframe for processing expedited rate filings would not allow the Commission Staff or impacted parties adequate time to review PSE's application or to engage in meaningful discovery on the Company's proposed revenue requirement. The expedited rate filing process proposed by PSE would fail to adequately protect ratepayers because it would not allow the parties and the Commission sufficient review time to ensure that excessive or imprudent expenditures are removed from the Company's revenue requirement. The accelerated and cursory review contemplated under the expedited rate filing process would inappropriately remove important regulatory safeguards in the ratemaking process, to the detriment of ratepayers.

**Q. DO YOU HAVE ANY OTHER CONCERNS WITH THE EXPEDITED RATE FILING PROPOSAL?**

**A.** Yes. In a general rate case proceeding, the Commission seeks to establish rates that are just and reasonable by undertaking a comprehensive review of all components of a utility's costs and revenues. An expedited rate review process that excludes critical components of a utility's revenue requirement, such as the return on equity, hinders the Commission's ability to set rates that adequately reflect all elements of the utility's cost structure. This makes it difficult to ensure that the established rates are just and reasonable and raises the risk that rate increases could be authorized without full consideration of offsetting reductions to the utility's cost structure that fall outside of the scope of the expedited rate filing process.

**Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE COMPANY'S EXPEDITED RATE FILING PROPOSAL?**

**A.** I recommend that the Commission reject PSE's request to establish a formal expedited rate filing process. In order to ensure that rates are just and reasonable and to provide impacted parties with an adequate opportunity to thoroughly vet all components of the Company's costs, the Commission should only allow PSE to adjust its base rates in a full general rate case proceeding.

**Q. DOES THIS CONCLUDE YOUR RESPONSE TESTIMONY?**

**A.** Yes, it does.

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