Exh. TES-1T
Dockets UE-170033/UG-170034
Witness: Thomas E. Schooley

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

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

TESTIMONY OF

Thomas E. Schooley

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Policy
Adj. 14.05, Storm Damage
Electric Cost Recovery Mechanism
Expedited Rate Filing

June 30, 2017

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Thomas E. Schooley. My business address is The Richard Hemstad Building, 1300 S. Evergreen Park Drive S.W., P.O. Box 47250, Olympia, WA 98504. My email address is: tschoole@utc.wa.gov.

Q. By whom are you employed and in what capacity?

A. I am employed by the Washington Utilities and Transportation Commission ("Commission") as the Assistant Director - Energy Regulation, Regulatory Services Division. My responsibilities include direct supervision of the Commission's Regulatory Analysts who review tariff filings and other applications of regulated electricity and natural gas companies, and make recommendations for Commission decision on those filings and applications.

Q. How long have you been employed by the Commission?

A. I have been employed with the Commission since September 1991.

Q. Please state your educational and professional background.

A. I received a Bachelor of Science degree from Central Washington University in 1986. I met the requirements for a double major in Accounting and Business Administration-Finance. I also have a Bachelor of Science degree in geology from the University of Michigan. I passed the Certified Public Accountant exam in May

1989. Since joining the Commission, I have attended several regulatory accounting courses, including the summer session of the Institute of Public Utilities.

Before obtaining my current position, I held several other positions including Accounting Manager of the Energy Section and Regulatory Analyst. I testified in Docket UE-960195 involving the merger between Washington Natural Gas Company and Puget Sound Power & Light Company ("Puget"). I was the lead Staff analyst in several applications for accounting treatment, including Puget Sound Energy, Inc. Dockets UE-971619/UE-991918. I testified in the Avista general rate case, Docket UE-991606, and Avista's energy recovery mechanism, Dockets UE-000972, UE-010395, UE-011595, and UE-030751. I also assisted in the development of Staff testimony in Puget's "PRAM 2" case, Docket UE-920630, and I presented the Staff recommendation on environmental remediation in Puget Docket UE-911476.

I analyzed PacifiCorp's proposed accounting treatment of Clean Air Act allowances in Docket UE-940947, and participated in meetings of PacifiCorp's inter-jurisdictional task force on allocations. I testified in PSE's power cost only rate case, Docket UE-031725; PSE's general rate cases, Dockets UE-072300/UG-072301 and UE-090704/UG-090705; and PacifiCorp's general rate cases, Dockets UE-032065, UE-050684, UE-061546, *et al.*, and UE-100749. I presented Staff's positions in PSE's decoupling and expedited rate filings, Dockets UE-121373/UE-130137.

I have prepared detailed statistical studies for use by commissioners and other Commission employees, and have interpreted utility company reports to determine its compliance with Commission regulations. I have also presented Staff recommendations to the Commission in numerous open public meetings.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. I present Staff's policies supporting the recommendations for PSE's revenue requirement and resulting rates. My testimony also provides Staff's recommendations for the Company's storm damage accounting, proposed electric cost recovery mechanism and expedited rate filings.

Q. Have you prepared any exhibits in support of your testimony?

A. Yes, I have two additional exhibits:

- Exh. TES-2, Charts of Storm Events
- Exh. TES-3, Storm damage expenses by periods ending September 30

III. SUMMARY OF STAFF'S PROPOSALS

Q. Please give a brief description of Staff's proposals.

A. Overall, Staff recommends a 2.2 percent reduction to PSE's existing electric revenues and a 6.6 percent reduction to PSE's existing gas revenues. Staff bases its case on a 7.37 percent weighted average cost of capital with the return on equity at 9.2 percent and equity as 48 percent of total capital.

Q. Who are Staff's witnesses in this case?

A. Staff's witnesses and the topics addressed by each is below.

a. David Parcell -- Cost of Capital. Mr. Parcell proposes an overall rate of return of 7.37 percent based on a return on equity of 9.2 percent with a capital structure of 48 percent equity.

b. Melissa Cheesman – Revenue Requirements models. Ms. Cheesman presents Staff's revenue requirement models and Staff's overall revenue requirement recommendation.

c. David Gomez -- Power costs. Mr. Gomez addresses the prudence of transmission contracts and the Wells power purchase agreement; hydro licensing costs; wind integrations costs; maintenance costs in the power cost model for gas-fired generation plants; and revisions to wind plant capacity factors.

d. Kyle Frankiewich – Energy Imbalance Market. Mr. Frankiewich addresses the costs and benefits of PSE's participation in the energy imbalance market and impact of the Clean Air Rule.

e. Betty A. Erdahl – Investor-supplied working capital. Ms. Erdahl recommends revisions to the investor-supplied working capital to improve its clarity and a straight-forward way to allocate working capital to the industries and non-utility operations resulting in proposed adjustments to decrease rate base for electric and gas operations.

f. Chris McGuire – Depreciation. Mr. McGuire proposes a fair and equitable method to recover the depreciation costs due to the early retirement of Colstrip.

g. Christopher Hancock – Colstrip closure, use of treasury grants. Mr. Hancock addresses the financial aspects of the costs to close Colstrip and presents an alternative to PSE's plan to finance future remediation costs.

h. E. Cooper Wright – Rate base additions. Mr. Wright presents Staff's testimony about rate base additions, including the acquisition of the Buckley natural gas system.

i. Jennifer Snyder – Glacier Electricity Storage. Ms. Snyder addresses the Glacier battery storage plant.

j. Elizabeth O'Connell – Environmental remediation cost recovery, rate case costs, water heater rentals. Ms. O'Connell presents Staff's plan for recovering the costs of environmental remediation for projects other than Colstrip. She also comments on Adjustment 13.12, Rate Case Costs. Additionally, Ms. O'Connell presents a plan concerning natural gas water heaters.

k. Jing Liu – Decoupling, temperature normalizing, low-income program. Ms. Liu presents Staff's review of PSE's decoupling plan. She also reviewed PSE's temperature normalizing adjustment and proposes improvements to the process.

l. Jason Ball – Electric and gas cost-of-service, rate spread, and rate design. Mr. Ball accepts the electric cost-of-service studies per the agreement in

Docket UE-141368; proposes revisions to the gas cost-of-service study; proposes changes to the electric rate design; and accepts PSE's proposed gas rate design.

m. Andrew Roberts – Service Quality Index 5, Customer Access Center Answering Performance. Mr. Roberts addresses Staff's concerns with how PSE proposes to include integrated voice response calls in the Customer Access Center Answering Performance metric.

IV. STAFF POLICY

A. Relevant History

Q. Please describe the genesis of today's general rate case filing, Dockets UE-170033/UG-170034.

A. It is important to note the history of PSE's filings over the past five years. PSE last filed a general rate case (GRC) in 2011, identified as Dockets UE-111048/UG-111049 (2011 GRC).[1] That filing established what PSE today considers the base rates for its customer schedules, such as Schedule 7 for residential use. Rates established in the 2011 GRC went into effect on May 14, 2012.

On October 25, 2012, PSE filed a petition for a decoupling mechanism in Dockets UE-121697/UG-121705 (*consolidated*), Decoupling Plan.[2]

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[1] *Wash. Utils & Transp. Comm'n. v. Puget Sound Energy*, Dockets UE-111048/UG-111049.

[2] *In the Matter of the Petition of Puget Sound Energy, Inc., and Northwest Energy Coalition for an Order Authorizing PSE to Implement Electric and Natural Gas Decoupling Mechanisms and to Record Accounting*

PSE filed to increase rates for delivery costs only on February 1, 2013, in Dockets UE-130137/UG-130138 (*consolidated*), Expedited Rate Filing (ERF).[3] The decoupling filing and the ERF were not consolidated, but were considered on an identical procedural schedule.

The Commission issued final orders in both matters on June 25, 2013, ("Order 07") granting the petition in the decoupling plan, and authorizing rates in the ERF. Rates took effect on July 1, 2013, 5 months after the date of the filing and just over 13 months from the rate effective date in the 2011 GRC. This set the stage for the following four years up to now.

Q. Please describe the highlights of the dockets approved by the Commission in June 2013.

A. The two main outcomes of the 2013 proceedings were the establishment of a decoupling plan intended to remove PSE's incentive to sell more electricity and a rate plan that allowed for scheduled rate increases over the next few years. The expedited rate filing was the basis for the scheduled increases. Only revenues to recover "delivery costs" were considered. Delivery costs included transmission, distribution, and administration and general expenses. The decoupling plan used the delivery costs divided by the number of customers to set an Allowed Revenue per Customer. The actual number of customers in the next period times the Allowed Revenue per Customer determined PSE's revenue for the delivery portion of the

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Entries Associated With the Mechanisms, Dockets UE-121697/UG-121705 (consolidated) ("Decoupling Dockets")

[3] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-130137/UG-130138

business. Power costs were recovered in the traditional manner of cents per kilowatt-hour (kWh).

The Allowed Revenue per Customer was increased each year in the rate plan. Power costs were constant until reset in a power cost only rate case (PCORC).

The last element of the decoupling plan is how the allowed revenues are collected. Customers still receive bills based primarily on a cents per kWh basis. This creates a natural variance between allowed revenues and collected revenues. This variance is captured in the next year's reset of the Allowed Revenue per Customer. The above description is, of course, a simplified version of the overall plan.

PSE was able to file a rate increase in the spring each of the next few years with a rate increase on May 1. This rate increase captured the rate plan percentage increase to the allowed revenue per customer, plus or minus the true-up of the variance in the prior year.

Customer protections in the plan include a maximum 3 percent increase of the annual rate and a profit sharing plan if PSE was able to earn more than its authorized rate of return. PSE was instructed to file a general rate case no sooner than 2015 and no later than 2016.

Q. What happened as 2016 approached and PSE needed to file a GRC?

A. PSE opted to not file a GRC in 2015. As 2016 approached, Staff became aware of possible rate filings by three other utilities creating a collision of work in a short period of time. Staff approached PSE and all parties to the prior cases with the idea of postponing PSE's filing until 2017. All were willing to do so. The parties filed a joint petition to modify Order 07 which the Commission approved in notice on March 17, 2016. The agreement extended the date of the required GRC to January 17, 2017. That brings us to the filing before us now.

Q. Are there any salient statements from the Commission in its determination of the terms of the decoupling and rate plan?

A. Yes. The Commission required more frequent reporting of PSE's results of operations and capital expenditures.[4] And further states:

> We approve the rate plan in part because it is an innovative approach that will provide incentives to PSE to cut costs in order to earn its authorized rate of return. It is important that the Commission monitor how, and how well these incentives, operate to improve efficiency and reduce costs <u>that ultimately will mean rates to customers that are lower than they would be absent these gains in efficiency</u>.[5] (*Emphasis added.*)

Q. How does Staff interpret this statement by the Commission?

A. Staff understands the Commission was allowing PSE the opportunity to over-earn for a period of time with the understanding that the next general rate case will be based on a cost structure which may show a need for lower rates. Evidence to this need is that PSE's rate of return has improved since 2013 to the point that it has shared over-earnings in the last three rate plan filings. The following table shows PSE's normalized rate of return since the start of the rate plan.

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[4] Order 07 ¶ 213.
[5] Order 07 ¶ 214.

Table 1 **PSE Normalized Rate of Return**

	Results of Operations	Earnings Sharing	After Earnings Sharing	*CBR Docket*
Electric				
2013	7.56%			*140536*
2014	7.74%			*150528*
2015	8.05%	0.14%	7.91%	*160375*
2016	8.06%	0.15%	7.91%	*170221*
Gas				
2013	7.34%			*140537*
2014	7.87%	0.05%	7.82%	*150529*
2015	8.17%	0.20%	7.97%	*160376*
2016	7.93%	0.08%	7.85%	*170222*

Q. What does this table tell us?

A. It tells us that PSE has indeed improved its earnings and has benefited from doing so. This was the intention of the rate plan. PSE exceeded its authorized rate of return, 7.77 percent, by up to 40 basis points in gas and 30 basis points in electric operations. We salute them on achieving these goals. It is now time to reset the program and a rate reduction is therefore reasonable.

B. Current Proceeding

Q. Please describe the overall regulatory policy Staff advocates in this docket.

A. Staff's analysis and recommendations are intended to bring reason and fairness to rates paid by today's customers while being mindful that the costs of today must not unreasonably be shoved into the future. Staff attempts to thread this needle of reasonable outcomes both temporal and practical. We also re-introduce PSE to the concept of risk since it seems to be dissatisfied with the numerous risk-mitigation measures granted by the Commission in recent years.[6]

Q. Please describe these risk related measures.

A. Staff witness Mr. Parcell presents many types of "regulatory mechanisms that are beneficial to the Company from a financial standpoint."[7] Trackers and riders both allow PSE to recover its costs dollar for dollar. These measures include the federal incentive tracker, the property tax tracker, and the conservation rider. Other measures significantly reduce the time lag from an investment or cost incurrence, such as the power cost only rate case, the power cost adjustment, the purchase gas adjustment, and the gas cost recovery mechanism.

Q. What other mechanism does PSE use to reduce accounting risk?

A. PSE makes regular use of accounting petitions to reduce risk. By risk I refer to variability in corporate earnings. Accounting petitions request Commission authority for the utility to deviate from the established means of cost recognition by deferring a cost in one period for recovery in later periods with the regulator's grant of revenues to recover that cost in the later period. In other words, costs incurred in one time period will reduce earnings in that year. If the Commission grants the petition to defer the costs to a later time, the utility's earnings will improve that year. Those costs will be recognized in later accounting periods, usually over several

[6] Doyle, Exh. DAD-1T at 14:1 – 25:18
[7] Parcell, Exh. DCP-1T at 19:6-7.

periods. This action smooths out the impact of the expense, therefore reducing variation in the earnings.

Q. To what degree has PSE used accounting petitions or deferred accounting.

A. PSE's response to Staff data request 118 shows the following balances in various regulatory asset and liability accounts as of September 30, 2016:

Account 182.1, Extraordinary property Losses	$123,187,221
Account 182.2, Unrecovered plant and regulatory study costs	$9,076,683
Account 182.3, Other regulatory assets	$616,644,567
Account 186, Miscellaneous deferred debits	$233,106,612
Total deferred assets	$982,015,083
Account 253, Other deferred credits	($358,723,385)
Account 254, Other regulatory liabilities	($131,176,563)
Total deferred liabilities	($489,899,948)
Net deferred accounts	$492,115,135

In sum, PSE has nearly one-half billion dollars in deferred accounts. This is real money. Clearly PSE uses deferred accounting to a high degree.

Q. Please explain your comments about the costs of today being pushed into the future.

A. There is a tendency for all parties, Staff included, to see any postponement of a period cost, i.e., any cost incurred in the present period, as a good way to reduce rates. But all that means is that customers in future periods will pay an expense of the past. This is unjust to those future customers if there is no associated benefit to those future customers.

Staff proposes a delicate balance between today's ratepayers, future ratepayers, and shareholders. In depreciating only the remaining service value of Colstrip 1 and 2, today's ratepayers pay only their fair share of the use of the facility. In amortizing the substantial depreciation reserve imbalance over 18 years, the loss in service value associated with the decision to retire units 1 and 2 are shared by today's ratepayers and tomorrow's ratepayers while the company is made whole for its investment in the facility. The reduction to plant in service ensures that ratepayers only pay, and shareholders only compensated, for the fair value of the plant. In short, the company is made whole but ratepayers do not pay a full return on a mortally wounded investment. Otherwise the next 4.5 years of ratepayers are unfairly saddled with 50 percent of the facility's depreciation.

An example that avoids this problem are the proposals to repurpose the treasury grants. Both PSE and Staff propose to offset future decommissioning and remediation costs for Colstrip 1 and 2 with the existing treasury grants. Without offsetting decommissioning and remediation costs with treasury grants (and without including decommissioning and remediation costs as a component of negative salvage in the depreciation study), the decommissioning and remediation costs will be paid by future generations of ratepayers. The goal is to ensure that future ratepayers are not unduly burdened by the decisions of today.

Q. What is PSE's complaint about Commission policies over the past few years?

A. Mr. Doyle claims that the earnings sharing element in the 2013 rate plan is unfair. He complains that the normalizing adjustments, such as temperature and power costs, cause PSE to look profitable when they are not. He also points to very minor "normalizing" adjustments such as the Montana excise tax (minus $99,000 impact to revenue requirement), injuries and damages (minus $112,000 electric, plus $93,000 gas) as contributing to inequity in sharing. His other normalizing items are rate case expenses (plus $428,000 electric, plus $452,000 gas) and bad debts (minus $1,100,000 electric and minus $57,000 gas), which when summed, start to look material. But even the $1.1 million bad debt adjustment only affects the return on rate base by 0.01 percent.[8] One-one hundredth of one percent is hardly a material impact on an electricity operation with $2 billion in annual revenues.

Q. What about the major adjustments of temperature and power cost?

A. While temperature and power costs are material, these adjustments are necessary to compare utility operations over time. It would be unfair to both PSE and customers to judge utility operations and profits on simple per books results.

Q. Does Mr. Doyle have a point the Commission should take into account?

A. Perhaps. But Mr. Doyle's testimony excludes important context. Among PSE's costs for delivery, fixed power, and variable power, Mr. Doyle's complaints would only apply to the variable power costs. Temperature normalizing is a moot point for

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[8] This list is found in Doyle, Exh. DAD-1T at 19:11 – 19:18

the decoupled delivery cost. PSE also proposes that fixed power cost be included in the per customer decoupling calculation. If so, temperature will no longer have an effect on recovery of delivery costs *or* fixed power costs. If PSE is able to manage its expenses to be less than what is built into the allowed per customer deliver cost, the Company may actually achieve greater profits than the authorized rate of return. These profits are subject to sharing.

Variable power costs and the revenues that cover variable power cost will be all that remains affected by normalizing temperature. The Commission has already mitigated some of that risk, too, because variable power costs are captured in the Power Cost Adjustment with a baseline set in a PCORC or in a general rate case. An assumed level of megawatt-hours of sales is set with the net variable power cost determined to meet that amount of sales. If loads or costs vary from those assumed, and they will, the actual costs at the end of a year will be compared to the baseline. Variances within a $17 million dead band will be the Company's responsibility. If the variance exceeds $17 million, either way, the excess will be shared with customers. This is why I said "perhaps" above, because a potential problem with profit sharing could exist if those variable power costs swung dramatically.

Q. What conclusion can you draw from this scenario?

A. It is quite possible that any excess earnings come from how the power cost adjustment works, not from decoupled delivery mechanism. If this is so, the earnings sharing mechanism may be flawed. If the purpose of the power cost sharing bands is to allow PSE to keep the benefit, or deficit, of managing its power costs, then it is unfair to take that benefit away in a sharing mechanism.

It is possible to break the three elements of PSE's electric business into profit centers. One element is for delivery, one is fixed production, and the third is variable power. The second and third elements could be combined. This breakdown would show the source of any excess earnings and whether it is fair to share that excess.

Q. What is Staff's response to PSE's request for a sharing band around the earnings test?

A. For the reasons stated above, Staff opposes the idea of a sharing band in the earnings test. But we do believe an analysis of the sources of return is advisable.

Q. Does Mr. Doyle bring up any other issues you wish to address?

A. Yes. Mr. Doyle, again, brings up his notion that there is a "traditional balance" in the utility's opportunity to earn its return. Staff is frustrated by that perspective because much of the last several years the Commission has focused on accommodating the risks facing the utility industry. If Mr. Doyle really believes that multiple rate filings, rate plans, decoupling mechanisms, gradualism for declining returns, power cost only cases, expedited cost recovery processes, and a multitude of other accommodations from both Staff and this Commission are out of balance, then I encourage PSE to stay out of rate cases or any kind of revenue filing and cease asking for deferred accounting. The Company is welcome to try going ten years with no rate filings or accounting petitions. The Company's performance over such a long period of time would certainly allow for the balanced opportunity to share risks.

Q. What risk-related issues does Staff address in response to Mr. Doyle's and PSE's concerns?

A. Staff's risk-related proposals include reducing the return on equity, revising dollar-for-dollar recovery of regularly occurring weather events, sharing the risks of participating in the energy imbalance market, sharing cost of Colstrip decommissioning and remediation through an interest bearing fund, and winding down the Colstrip 1 and 2 investment in a more measured manner.

Q. What other policy points does Staff address in this docket?

A. Staff also wishes to point out that utility regulation is not an exercise in precision. It is an exercise in reasonable outcomes. There are some adjustments that are relics of prior centuries, but may no longer provide meaningful information to develop rates today. Examples of this are the rate case expenses (Adjs. 11.12G, 13.12E), filing fee and excise tax (Adjs. 11.22G, 13.22E), and investment plan and employee insurance (Adjs. 11.17 and 11.18G, 13.17 and 13.18E). In PSE's case, these small adjustments are immaterial to final revenue requirements and rates. Staff proposes excluding the rate case adjustment in this docket, but we suggest that interested parties discuss the merits of maintaining these and other small items prior to PSE's next general rate case.

Q. Please sum up Staff's policies in this general rate case.

A. Staff promotes policies that:

- Make a dedicated effort to balance the cost impacts of plant obsolescence and early closure on today's ratepayers, tomorrow's ratepayers, and the company's shareholders;
- Carefully balance the risks for PSE and its customers; and
- Reduce the burdens of regulation by eliminating immaterial accounting adjustments.

V. STORM DAMAGE ACCOUNTING

Q. Please describe the current method for storm damage cost accounting.

A. PSE first determines if the costs to repair damages from a storm qualify for deferral based on the first day of a weather event where the daily system average interruption duration index (SAIDI) exceeds the Major Event Day threshold (Tmed) as defined by IEEE Standard 1366, IEEE Guide for Electric Power Distribution Reliability Indices. If so, then the first $8 million in a calendar year are a direct cost to PSE, but once that threshold is crossed then PSE defers all other qualifying storm damage costs in that calendar year. In a general rate case subsequent to that calendar year, the deferred costs are allowed in rates, if shown to be prudent, over the next four years.[9]

[9] Sometimes the subsequent general rate case is many years later. This GRC being a case in point. The 2012 snowstorm is already five years in the past. Recovering those costs over the next six years means customers of 2023 will pay an expense from early 2012.

Q. Does Staff agree with this method?

A. No, the method creates an inaccurate representation of storm patterns in PSE's territory and leads to excessive deferrals. The "qualifying" event threshold, or threshold major event day (Tmed), is easily met and the first $8 million of a year is also a low hurdle. In the past 6 years, 2011 through 2016, there were 23 qualifying storms. There are already four events in the first 5 months of 2017.[10] I do not consider these events "catastrophic storms" as labeled in Exh. KJB-14, Adj. 14.05, lines 19-27. Storms that occur on average every 3 months are by nature quite normal.

Q. Has any storm in the past 6 years been truly catastrophic?

A. Yes. On January 18, 2012, a snowstorm hit western Washington with devastating effect.[11] This one event caused $58.4 million in damages.[12] Exhibit TES-2 shows the qualifying events in the past 11 years where PSE deferred storm damage costs. The data shows only two that greatly exceed the fairly narrow range of all other events as measured by dollars or customer interrupt minutes. The "Hanukah Eve" event of 2006 and "Snowmageddon" were truly catastrophic.

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[10] Granted the Company's data shows there were no deferrals in 2011 and 2013. PSE Response to WUTC Staff Data Request No. 376 (SDR 376).

[11] Dubbed "Snowmageddon" by the local press.

[12] PSE adds three more events in 2012 totaling $1,924,630 to equal the $60,295,490 total for the "1/18/12 Snow Storm" on line 39 of Adj. 14.05, Exh. KJB-14.

Q. The Tmed to qualify as a deferrable event is based on a definition by the Institute of Electrical and Electronic Engineers (IEEE), Standard 1366-2003. Is this a reliable measure of storm severity?

A. No. The stated purposes of the Tmed methodology include to "present a set of terms and definitions which can be used to foster uniformity in the development of distribution service reliability indices" and, "to aid in consistent reporting practices among utilities."[13] In other words, this measure is intended to standardize outage data so utilities can be compared to each other, or over time. The standard does not address the relative severity of storm events. Nor is the standard intended to offer guidelines for cost deferral mechanisms.

Q. What is the historical rationale for using IEEE Std 1366?

A. Annex B of IEEE Std 1366-2012 describes the justification and process for development of the 2.5beta methodology, and states that "[T]he β multiplier of 2.5 was chosen because, in theory, it would classify 2.3 days per year as major events. If significantly more days than this are identified, they represent events that have occurred outside the random process that is assumed to control distribution system reliability."[14] For PSE, the current methodology is categorizing far more than 2.3 days per year as major events. To re-iterate, the intent of the Tmed measure is to enhance comparability between utilities, not to judge the severity of any given event.

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[13] IEEE Guide for Electric Power Distribution Reliability Indices Std. 1366-2012, p. 1
[14] Ibid., p. 22

Q. What is a better way to judge the extremity of events?

A. Dollars to repair the electrical grid and customer interrupt minutes are both transparent and practical measures. Exh. TES-2 presents charts of the past several years where it is obvious that two extraordinary events in the past 11 years far exceed the commonplace occurrences.

Q. Do you propose a threshold above which the costs of an extreme event may be deferred?

A. No. It does not appear that a bright line can be drawn to identify a threshold for deferrals. There is a broad gap from the ongoing events and those that greatly exceed the regularly occurring events. When it happens, there will be little doubt about whether the event is truly catastrophic or not.

Q. What is Staff's proposal?

A. In Staff's opinion, only the rare catastrophic storms deserve deferred treatment for the costs incurred to put the electrical system back together. Therefore, we propose to use an average of all the costs for storm damages in the past six years to set a reasonable level of ongoing cost recovery. We accept deferral of the January 2012 snowstorm and recommend this be recovered over 6 years. This means we reject the deferral of the storm damage deferrals "pending approval" in Exh. KJB-14, Adj. 14.05, lines 24-26. I reinstated those dollars into the proper time periods in the normal storm section in lines 3-8. My Exh. TES-3 shows the revised calculation of average storm costs for the test year ending September 30, 2016.

Q. How do you treat the over-amortization of the 2010 storm on line 22?

A. Staff appreciates PSE's recognition of this 2010 amortization extending to the beginning of the rate year.[15] I applied the $12.56 million credit to the remaining $50,186 item in 2010 and "paid off" the last several months of the 12/13/2006 "Hanukah Eve" wind storm. A credit of $5,877,031 still remains. I applied this credit to the total cost of the 2012 snowstorm reducing it to $52,493,829 from $58,370,860.

Q. What does Staff recommend for PSE's inclusion of storm damages occurring in October 2016 and January 2017, in PSE's update to Adj. 14.05?

A. Staff recommends the Commission reject these deferrals. The costs of these storms will be picked up in Staff's proposed six-year average in future rate cases.

Q. What is the effect of Staff's proposal on rate base?

A. By "un-deferring" the pending storm damages of the past 6 years, the rate base item investor-supplied working capital is reduced by $48,676,825 with corresponding deferred federal income taxes also reduced by $17,036,889 for a net rate base reduction of $31,639,936.[16]

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[15] Exh. KJB-1T at 44: 15-18

[16] The return on storm damage deferrals is accomplished through working capital. See Exh. BAE-3, Lines 744-753, and Lines 2331-2352. Therefore, this rate base reduction is shown as a reduction to working capital.

Q. What is the effect of Staff's proposal on expenses (or NOI)?

A. There are two components in the expense calculation. First, Staff increases the average annual expense for normal storms to $18,769,050, or $7,709,493 more than the test year level. Second, the remaining balance of the 2012 snowstorm, about $52.5 million, is amortized over six years, or $8,748,972 per year. This is $6,728,425 less than the test year amortization expense. Taken together, there is an increase of $981,068 in test year storm damage expenses compared to the actual per books expense. After federal income tax, this is a decrease to net operating income of $637,695.[17] The combined effect of the rate base reduction and the NOI decrease reduces revenue requirement by about $2.7 million.

Q. Is this a draconian change to PSE's recovery of storm damages?

A. No. PSE will receive an appropriate amount of its prior year storm damages through the averaging method. There may be consequences when methods are changed, but if the new method is fairer to all, then it is acceptable. The prior method has been in place since early 2005, but has shown to be biased in favor of the Company. By setting a reasonable representative level of storm damages in rates, fairness to customers will be restored by establishing a reasonable level of ongoing storm related repairs and only allowing deferrals of the costs of devastating storms therefore reducing rate base and the return it receives. The extraordinary 2012 snowstorm is fully recovered over a 6 year period. The Company suffers no substantive loss from this revision.

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[17] See Exh. MCC-2 at 5 and Exh. MCC-2 at 35-36.

Q. How does the advent of decoupling affect the recovery of storm damages?

A. This aspect of PSE's cost recovery must be considered in the Commission's deliberations. The costs in question are for transmission and distribution system repairs which are included in the calculation of the allowed revenues per customer. PSE will recover the storm damage repair costs in a stable manner by Staff's proposal. The Company does not suffer from a cost recovery perspective.

Q. If the recovery of storm damages are largely based on a six-year average, what does vary over time?

A. With cost recovery on a per customer basis, PSE recovers its average storm repair costs on a stable basis over time. PSE will see variation in financial expenses and cash flow as the repairs to the grid are made as events occur. This is acceptable as the rates will recover storm repair costs over a 6-year period as long as the method persists over time.

Q. How should this six-year average method be treated in commission-basis report or in PSE's proposed expedited rate filing process?

A. If approved by the Commission, the storm damage repair expense will use the averaging method as one of the "necessary adjustments as accepted by the Commission in the utility's most recent general rate case".[18]

[18] WAC 480-100-257(2)(a)

Q. Is there another aspect to storm repair costs that Staff recommends?

A. Yes. Staff recommends that, going forward, the amortization of costs deferred for a catastrophic event begin in the month when the repair work is completed. This treatment is parallel to that of new plant. When a new infrastructure project is placed into service the depreciation of the plant begins that month. In essence, after a catastrophic storm new plant is created and placed into service. Much of the newly repaired plant is added to rate base plant accounts, or capitalized. Repair costs and other costs to accomplish the monumental task should be treated the same way.

Q. Should the deferral balance of repair costs for catastrophic storms receive a rate of return?

A. Yes, but only to the extent the deferred balance contributes to investor-supplied working capital.

VI. ELECTRIC COST RECOVERY MECHANISM

Q. Please describe PSE's proposed Electric Cost Recovery Mechanism?

A. PSE, through the testimony of three witnesses, proposes an electric cost recovery mechanism (ECRM). PSE requests an ECRM "in order to accelerate the replacement of targeted reliability improvements".[19] The Company presents its goals and rationale in the testimonies of Ms. Gilbertson and Ms. Koch; Ms. Barnard presents the rate making treatment. Basically, the plan is very similar to the natural

[19] Exh. KJB-1T at 73:16-17.

gas cost recovery mechanism which has been in place for a few years. PSE would present an electric reliability plan to accelerate the replacement of high molecular weight underground cable (HMW cable) and to improve the worst performing circuits. Both projects aim to reduce the number and duration of power outages.[20] PSE believes the ECRM "would allow for more consistent work planning and an accelerated recovery of the increased investment."[21]

Q. Is there a substantive difference in the work performed for PSE's gas CRM and that in PSE's proposed Electric Cost Recovery Mechanism?

A. Yes. PSE's gas CRM was established for the express need to remove potentially unsafe natural gas pipelines. This need was identified by the Commission Pipeline Safety section. The intent of the gas CRM is to enhance the safety of the natural gas system by offering the incentive of reducing the regulatory lag on the new pipes installed to replace the older suspect pipes. Other gas distribution utilities face the same problem and have this program available to them.[22] PSE's Electric CRM is presented as a reliability enhancement program and no safety risk has been identified in relation to the provision of electric service.

Q. How does PSE's proposed Electric Cost Recovery Mechanism work?

A. PSE proposes that the costs of the two programs mentioned above will be tallied over the course of a calendar year. On July 1 of the year PSE will file its actual and

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[20] Exh. BKG-1T at 34:12-15.
[21] Exh. BKG-1T at 34:16-17.
[22] Cascade Natural Gas also uses the CRM program for replacing similar gas mains.

forecasted expenditures for the year. PSE would file again on November 30 with actuals through October and estimates for November and December. A revenue requirement for these specific investments will be determined with rates effective on January 1. The only costs included in the ECRM revenue requirement are depreciation expense, a return on the plant, and associated income taxes.[23] As with the gas CRM, this accounting treatment is straightforward and does not rely on deferrals of costs nor an accrual of interest for later recovery.

Q. Does Staff support the Electric Cost Recovery Mechanism?

A. No, I oppose the proposal because it is unnecessary. Ms. Gilbertson states that PSE seeks approval of "an Electric Reliability Plan." The Commission has a natural gas safety section to evaluate the gas safety plan required by the gas CRM. At present there is no similar group at the Commission dedicated to electricity. Staff is concerned that the approval of an electric reliability plan is functionally a pre-approval of those investments. The topic of distribution planning is currently a subject in the integrated resource plan rulemaking, Docket U-161024.

Staff wonders why PSE claims the ECRM will "allow for more consistent work planning and an accelerated recovery of the increased investment."[24] PSE has a public service obligation to provide safe, reliable service.[25] Staff also wonders why PSE needs an incentive to create a consistent work plan, or a structured mechanism to provide an incentive to find the time and resources to address the worst

[23] Exh. KJB-1T at 74:11-13.
[24] Exh. BKG-1T at 34:15-17.
[25] RCW 80.28.110 and RCW 80.28.010.

performing circuits, or an incentive to address the failure prone underground cable.[26] Work plans, for both time and resources, are wholly within management's control. PSE's management knows its public service obligations to all customers and receives a sufficient return on investments that meet that obligation. The existing regulatory ratemaking process already achieves the ECRM's stated goals and avoids pre-approval of Company investments.

Q. What process does PSE propose for the Electric Cost Recovery Mechanism?

A. Ms. Gilbertson suggests a collaborative process where Staff and the Commission have the opportunity to provide feedback on investment plans as they relate to reliability.[27]

Q. Does Staff agree with this process for the Electric Cost Recovery Mechanism?

A. No, Staff again sees no reason to deviate from the traditional ratemaking process. There is no identified problem with the traditional process where PSE is responsible to make wise decisions, file well-documented reasons for actions they take, and accept the fact that the Company will receive rates to recover any investment after that investment is in service and in the due course of Commission proceedings.

Q. What is staff's recommendation for PSE's Electric Cost Recovery Mechanism?

A. Staff recommends this proposal be rejected.

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[26] Exh. BKG-1T at 33:17-20.
[27] Exh. BKG-1T at 34:1-6.

VII. EXPEDITED RATE FILING

Q. What does PSE propose to reduce regulatory lag in general?

A. In 2013, PSE proposed and the Commission accepted an expedited rate filing (ERF) and a rate plan. Ms. Barnard presents a similar request in her testimony, but only for an expedited rate filing, or filings, to follow this GRC. The request is basically asking the Commission to formalize procedures for an ERF so that the process can be used in the future.

Q. What has transpired since PSE filed this GRC in January this year?

A. On March 30, 2017, the Commission proposed revisions to its procedural rules including rules for a "limited rate proceeding," which is essentially the same as an expedited rate filing. Comments about Docket A-130355 were due on May 15, 2017, with a workshop on June 12, 2017. PSE provided comments in Docket A-130355 in line with its proposals in this GRC.

Q. What is your opinion of an ERF, or limited rate filing?

A. I accept this process and was the witness in the ERF Dockets UE-130137/UG-130138. This method is a far preferable way to reduce regulatory lag than any special tracker mechanisms because an expedited rate filing is based on actual historical data. An ERF is limited in scope with few, or no, pro forma adjustments and holds constant certain controversial rate making elements such as cost of capital and rate spread/rate design.

Q. Would an ERF, or similar filing, address the same concerns raised in the proposal for the Electric Cost Recovery Mechanism?

A. Yes. The ERF gives ample opportunity to capture the costs of improvements to the underground conduit failures and improving reliability on poor performing circuits. The lag on recovery of the return on these rate base additions will be considerably reduced.

Q. What is your recommendation for an ERF?

A. An order in the rulemaking Docket A-130355 will be issued eventually. At that time, the Commission's decisions will inform PSE of a possible formalized procedure for limited issue rate filing, or not. If not, I recommend the Commission accept PSE's proposal for an ERF based on the method used in the ERFs in Dockets UE-130137/UG-130138.

VIII. CONCLUSION

Q. What is Staff's recommendation?

A. Staff recommends that the Commission:

- Accept the revisions proposed by Staff to the storm damage deferral mechanism.
- Reject the electric cost recovery mechanism
- Approve some form of an expedited rate filing.

Q. Does this conclude your testimony?

A. Yes.