Exh. JL-1CTr
Dockets UE-190529/UG-190530 and
UE-190274/UG-190275 (*consolidated*)
Witness: Jing Liu
REDACTED VERSION

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**DOCKETS UE-190529 and UG-190530 *(consolidated)***
In the Matter of the Petition of **PUGET SOUND ENERGY** **For an Order Authorizing Deferral Accounting and Ratemaking Treatment for Short-life UT/Technology Investment**	**DOCKETS UE-190274 and UG-190275 (*consolidated*)**

REVISED TESTIMONY OF

Jing Liu

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Results of Operations and Revenue Requirements,
Restated and Pro Forma Temperature Normalization,
Power Cost, Attrition Analysis

November 22, 2019
Revised December 17, 2019

CONFIDENTIAL PER PROTECTIVE ORDER – REDACTED VERSION

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jing Liu, and my business address is 621 Woodland Square Loop SE, Lacey, Washington, 98503. My business mailing address is P.O. Box 47250, Olympia, Washington, 98504-7250. My business email address is jing.liu@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 a regulatory analyst in the Energy Section of the Regulatory Services Division.

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

A. I have been employed by the Commission since 2008.

Q. Please state your qualifications to provide testimony in this proceeding.

A. I hold a Bachelor's degree in English Language and Literature, a Master of Arts degree in organizational communication and a Master of Science degree in communication technology and policy from Ohio University. I completed four years of doctoral study in public policy at Ohio State University. I worked as a graduate research associate at the National Regulatory Research Institute (NRRI) from 2005 to 2007. I worked in the telecommunications section of the Commission between

2008 and 2014 where I was responsible for developing and implementing telecommunications universal service policies and designating and certifying Eligible Telecommunications Carriers in Washington. I have been working in the Energy Regulation Section of the Commission since 2014. In this role I have been the lead analyst across a number of topics, including decoupling, temperature normalization, low income bill assistance, purchased gas adjustments, gas pipeline cost recovery mechanisms, residential exchange credits, and treasury grants.

Q. Have you previously testified before the Commission?

A. Yes. I provided testimony to the Commission in proceedings addressing United Telephone Company of the Northwest Inc.'s intrastate access charges (UT-081393), the acquisition of Verizon Northwest, Inc. by Frontier Communications Corporation (UT-090842), the acquisition of Qwest Corporation by CenturyLink, Inc. (UT-100820), Frontier Communications Northwest, Inc.'s petition for competitive classification (UT-121994), Avista Corporation's General Rate Case (GRC) (UE-160228/UG-160229), Puget Sound Energy's GRC (UE-170033/UG-170034), Avista's depreciation study (Dockets UE-180167/UG-180168) and Northwest Natural Gas's GRC (UG-181053).

II. SCOPE AND SUMMARY OF TESTIMONY

Q. What is the scope and purpose of your testimony?

A. I present Staff's calculation of Puget Sound Energy's ("PSE's" or "Company's") revenue requirements for its electric and natural gas operations. This portion of my testimony responds to the testimony of PSE witness Susan Free. I also present Staff's attrition analysis in response to PSE witness Ronald Amen.

Additionally, I provide an updated baseline rate for PSE's Power Cost Adjustment (PCA) mechanism, including Staff's adjustments to rate year power cost in response to the testimonies of Company witnesses Paul Wetherbee and Ronald Roberts. I also provide Staff's recommendation on electric and gas temperature normalization in response to Company witness Lorin Molander's testimony.

Q. Did you review any specific adjustments in this proceeding?

A. Yes. I present Staff's recommendations on the following adjustments:

- Adjustment 6.01 Revenue and Expense
- Adjustment 6.02 Temperature Normalization
- Adjustment 6.04 Tax benefit on interest
- Adjustment 7.01 Power Cost
- Adjustment 7.02 Montana Energy Tax
- Adjustment 7.10 Energy Management System

Q. Please summarize your recommendations on revenue requirement, including your recommendation with respect to attrition allowances.

A. I recommend revenue requirement increases of $50 million for electric operations and $38.4 million for natural gas operations, based on the modified historical test year approach.

With respect to PSE's request for an attrition allowance, my analysis shows an attrition-adjusted revenue *sufficiency* of $~~3.9~~2.5 million for electric operations and an attrition-adjusted revenue deficiency of $~~9.4~~12.1 million for gas operations. I conclude that the evidence does not support a need for an attrition allowance in this case. Staff witness McGuire reaches the same conclusion, but on policy grounds.

Q. Please summarize your recommendations with respect to power costs.

A. My revision to PSE Adjustment 7.01 reflects a number of adjustments that Staff witness David Gomez and I make to the Company's rate year power cost. Collectively, our adjustments accomplish the following:

- Remove expenses related to the Colstrip forced outage in 2018;
- Remove Colstrip major maintenance expense budgeted in 2020;
- Remove the proposed increase to Colstrip Units 3 & 4 operating and maintenance (O&M) expense in the rate year;
- Reduce the equity adder for the Centralia Power Purchase Agreement (PPA);
- Update the major maintenance cost for Fredonia major inspection cost;
- Revise wind facilities' maintenance contract expense and royalties; and
- Revise variable power cost model result.

My testimony on power cost focuses on Colstrip major maintenance expense, Colstrip O&M expense, Centralia PPA Equity Adder, Fredonia major inspection cost and wind facilities' maintenance cost and royalties.

With respect to Colstrip major maintenance in 2020, I recommend the Commission not include the budgeted major maintenance expense in the rates due to high risk of over estimation in the draft budget. Instead, the Commission should allow the Company to defer and recover the actual cost in the next GRC.

With respect to Colstrip O&M, I recommend the Commission use the test year expense because the proposed changes are not measurable at this time and because the Company has a chronic issue of over budgeting on this expense.

With respect to Centralia PPA Equity Adder, I recommend the Commission revise the adder rate to reflect the current federal income tax.

With respect to Fredonia plant major inspection cost, I recommend the Commission authorize the normalized cost based on the actual cost known at this time.

With respect to wind facitlities' rate year maintenance cost and royalties, I recommend the Commission adopt the expense amount based on Staff-recommended wind generation level for the rate year.

With respect to variable power cost result from the AURORA model, Gomez and I recommend the Commission require the Company to continue to estimate rate year power cost based on the average of 80 run results and restore wind resource capacity factors.

Collectively, Gomez's and my recommendations regarding power cost reduce the revenue requirement by $10.7 million (restating and pro forma adjustments combined).

Q. Please summarize your recommendations with respect to temperature normalization.

A. My revisions to PSE Adjustments 6.01 and 6.02 are related to temperature normalization. I recommend the Commission reject PSE's two-model reconciliation approach to develop weather normalized sales. PSE's approach is problematic because the result from a system model inherently is non-reconcilable to the result from the schedule level models. Further, the system model is not suited for schedule-level revenue adjustments.

Instead, the Commission should require PSE to apply rate schedule level analysis to rate schedule level revenue adjustments to reflect normal temperature. My recommendation reduces the Company's electric revenue requirement by $3.6 million, and increases the Company's gas revenue requirement by $0.8 million (restating and pro forma adjustments combined).

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

A. Yes. I prepared Exhibits JL-2 through JL-23.

Exh. JL-2 shows Staff's Electric Revenue Requirement Model.

Exh. JL-3 shows Staff's Natural Gas Revenue Requirement Model.

Exh. JL-4 shows the impact of Staff's adjustments to electric revenue requirement.

Exh. JL-5 shows the impact of Staff's adjustments to gas revenue requirement.

Exh. JL-6 shows Staff's recommendation on electric temperature normalization.

Exh. JL-7 shows PSE's backcast on electric sales in test year.

Exh. JL-8 shows Staff's recommendation on gas temperature normalization.

Exh. JL-9 shows PSE's backcast on gas sales in test year.

Exh. JL-10C shows a comparison of Colstrip major maintenance cost as budgeted, actual, and the amount built in rates.

Exh. JL-11 shows PSE's explanation on Colstrip major maintenance in 2017 and 2018.

Exh. JL-12C shows PSE's support for Colstrip major maintenance in 2020.

Exh. JL-13C shows PSE's response to WUTC Data Request No 75.

Exh. JL-14C shows Talen's Colstrip common cost budget.

Exh. JL-15C shows a comparison of budgeted and actual Colstrip O&M expense.

Exh. JL-16 shows Staff's revised Centralia PPA Equity Adder.

Exh. JL-17C shows Staff recommended variable power cost.

Exh. JL-18C shows PSE's explanation on the difference between a single run and 80 runs.

Exh. JL-19 shows Staff's attrition analysis result.

Exh. JL-20 shows a comparison of Staff's and PSE's attrition base and growth factor.

Exh. JL-21 shows PSE's response to AWEC Data Request No. 20 cover letter.

Exh. JL-22 shows PSE's revised response to AWEC Data Request No. 20 cover letter.

Exh. JL-23C shows PSE's capital expenditure plan for the next five years.

III. RESULTS OF OPERATIONS AND REVENUE REQUIREMENTS

Q. Please summarize the Company's requested revenue increase.

A. PSE calculated a $101.4 million revenue deficiency (net revenue change) for its electric operations from the conventional modified historical test year approach (also referred to as the pro forma results). The Company then added an attrition allowance of $38.5 million, bringing its total requested increase for electric operations to $139.9 million.

PSE calculated a $53.7 million revenue deficiency (net revenue change) for its natural gas operations from the conventional modified historical test year approach. The Company then added an attrition allowance of $11.8 million, bringing its total requested increase for natural gas operations to $65.5 million.

PSE witness Susan Free presented the details of the Company's requested revenue in Table 1 at Page 2 of Exh. SEF-1T.

Q. Please summarize Staff's analysis of the Company's revenue requirement.

A. Based on a modified historical test year approach, Staff recommends revenue increases of $50.0 million for electric operations and $38.4 million for natural gas operations. As explained by Staff witness Chris McGuire, and as demonstrated by my attrition studies, the record does not support PSE's assertion that it requires an attrition allowance.

I have conducted independent attrition analyses for PSE's electric and gas operations. The results of those attrition studies indicate revenue deficiencies of $46.1 million for electric operations and $47.8 million for natural gas operations.

My attrition studies produce revenue deficiencies reasonably close to the revenue deficiencies produced through Staff's modified historical test year approach, indicating that the modified historical test year approach produces revenues sufficient to cover trended growth in costs.

Staff's revenue requirement is summarized in Table 1, below.

Table 1. Staff's Recommended Net Revenue

(amounts in millions)

DESCRIPTION	ELECTRIC	GAS	COMBINED
1. Revenue Change Before Attrition and Riders	$53.1	$70.7	$123.8
2. Changes to Other Price Schedules	-3.1	-32.4	-35.5
3. Net Revenue Change Before Attrition	$50.0	$38.4	$88.4
4. Attrition Adjustment	0.0	0.0	0.0
5. Net Revenue Change Recommended	$50.0	$38.4	$88.4

Q. What is Staff's recommendation on the Company's electric PCA baseline rate?

A. Based on Staff's analysis of PSE's pro forma power supply cost, Staff recommends the PCA baseline rate for variable production costs be set at $35.72 per MWh. This represents a reduction of $0.46 per MWh (-1 percent) from PSE's proposal.

Q. Please summarize Staff's adjustments to the Company's requested revenue.

A. I present Staff's electric revenue requirement model in Exh. JL-2 and gas revenue requirement model in Exh. JL-3. I list Staff's adjustments and their impact on net operating income (NOI), rate base and revenue requirement in my Exh. JL-3 (Electric) and my Exh. JL-4 (Gas).

IV. TEMPERATURE NORMALIZATION

A. Overview

Q. Please summarize the key findings of your testimony on electric temperature normalization.

A. I contest the Company's sales adjustments for both electric and natural gas temperature normalization developed by Company witness Lorin Molander. The related revenue adjustments are in Company witness Susan Free's Adjustments 6.02ER (restating) and 6.02EP (pro forma).

For electric temperature normalization, I recommend: (1) using the results from a schedule-level analysis instead of a system-level analysis, and (2) excluding Schedule 29 from the sales adjustment. My adjustment reduces the electric revenue requirement by $3,571,400 (restating and pro forma combined). The electric temperature normalization sales adjustment is set forth in Exh. JL-6.

A summary of the differences between the Company's proposal and Staff's recommendation is provided below in Table 2 for comparison.

Table 2. Staff and PSE Electric Temperature Normalization Adjustments

	PSE System Model (PSE Proposal)	PSE Schedule Model without Schedule 29 Adjustment (Staff Recommendation)	Difference (Staff – PSE)
Sales Adjustment			
kWh Adjustment	135,247,698	167,456,235	32,208,537
Adjustment as a % of Actual Sales for	0.67%	0.84%	0.16%

Weather Sensitive Schedules			
Revenue Adjustment			
NOI	$ 10,809,445	$ 13,492,927	$ 2,683,482
Revenue Requirement Impact	$ (14,386,103)	$ (17,957,503)	$ (3,571,400)

Q. Please summarize the key findings of your testimony regarding PSE's natural gas temperature normalization adjustment.

A. As with electric, Staff recommends using the results from a rate class-level analysis for gas temperature normalization instead of a system-level analysis. My adjustment increases the Company's gas revenue requirement by $798,500 (restating and pro forma combined). The gas temperature normalization sales adjustment is set forth in Exh. JL-7. The related revenue adjustments are in PSE witness Free's Adjustments 6.02GR (restating) and 6.02GP (pro forma).

Table 3 provides a comparison of PSE's and Staff's approaches.

Table 3. Staff and PSE Natural Gas Temperature Normalization Adjustments

	PSE System Model (PSE Proposal)	**PSE Schedule Model (Staff Recommendation)**	**Difference (Staff – PSE)**
Sales Adjustment			
Therms Adjustment	56,683,958	53,364,524	(3,319,434)
Adjustment as a % of Actual Sales for Weather Sensitive Schedules	5.0%	4.7%	-0.3%
Revenue Adjustment			
NOI	$ 13,405,008	$ 12,802,861	$ (602,147)
Revenue Requirement Impact	$ (17,776,238)	$ (16,977,738)	$ 798,500

Q. Could you please describe the purpose of temperature normalization?

A. Temperature normalization, also called weather normalization or revenue normalization due to temperature, is an adjustment to a company's test year revenue to reflect a level of sales under normal weather. It estimates the energy that a utility would have sold if the weather had been "normal."

Given that energy consumption is highly correlated with temperature, the Company's sales are subject to temperature swings that are out of the Company's control. Temperature normalization allows us to evaluate revenue sufficiency under normal weather and, prospectively, under the expectation that weather will be normal in the rate year. As a result, temperature normalization protects both a company and its customers from misleading revenue signals resulting from abnormal weather. Temperature normalization also enables us to compare a company's earnings from year to year, with temperature influence taken out of the equation.

For example, if a test year has a warmer winter than normal, a company's electric or gas sales would be lower than the normal level due to a relatively low heating load. In this example, a company's per-book revenue should be adjusted upward to a sales volume expected under a normal winter, as setting prospective rates relies on the assumption that temperature will be normal during the rate year. Without this adjustment, test year revenue would be lower than normal, perhaps even giving the impression that the company needs a rate increase when, from a weather-normalized perspective, revenues would be sufficient. The opposite would also be true if a test year has a colder winter than normal. A similar rationale can be applied to the relationship between summer temperature and electricity sales.

Q. What information is required to perform a temperature normalization adjustment?

A. Typically, temperature normalization involves three basic components: (1) calculation of deviation in test year heating degree days (HDD) or cooling degree days (CDD) from a "normal" benchmark;[1] (2) calculation of weather sensitivity coefficients from statistical models; and (3) identification of the number of customers for each weather sensitive schedule in the test year. The product of these three components produces an adjustment in energy sales.

Q. What is "normal" temperature for this purpose?

A. PSE uses the temperature data published by the National Oceanic and Atmospheric Administration (NOAA) for SeaTac International Airport. The Company aggregates hourly temperature readings into daily and monthly HDDs and CDDs and uses the rolling 30-year average HDDs and CDDs as the benchmark for normal weather conditions. It is consistent with PSE's practice in prior general rate cases (GRCs).

Q. Could you explain how to calculate temperature sensitivity coefficients?

A. Because energy consumption is typically highly correlated with temperature, HDD and CDD serve to explain variation in energy sales for most customer groups.[2] A

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[1] HDD measures the deviation in the actual temperature below the baseline temperature, commonly 60 or 65 degrees Fahrenheit. Higher HDDs indicate colder weather. CDD measures the deviation in the actual temperature above the baseline temperature, also commonly 60 or 65 degrees Fahrenheit. Higher CDDs indicate hotter weather. Using 65 as the baseline temperature, if the temperature is 51 degrees Fahrenheit, HDD is 14 and CDD is 0; if the temperature is 71 degrees Fahrenheit, HDD is 0 and CDD is 6.

[2] More specifically, energy consumption is highly correlated with temperature once the temperature exceeds a threshold that challenges human comfort. For example, as ambient temperature cools to below 65 degrees Fahrenheit, further decreases in temperature are highly correlated with increased heating load.

regression model is capable of producing weather sensitivity coefficients that quantify the amount of change in kilowatt-hour (kWh) or thermal sales per degree change in temperature. This coefficient multiplied by the total change in HDD or CDD and the number of customers determines the adjustment needed to achieve normal sales.

A. Staff Analysis of Electric Temperature Normalization Models

Q. Did the Company make any changes to its temperature normalization methodology since its last GRC? [3]

A. No. The Company uses largely the same methodology that it proposed in the 2017 GRC. In that case, I sponsored testimony contesting the Company's temperature normalization methods and results. The 2017 GRC ended with a settlement agreement in which the settling parties agreed to disagree on this issue.

In this GRC, I continue to believe that PSE's methodology is flawed and that the results on revenue adjustment are skewed. I discuss here the same problems I identified in the 2017 GRC. Furthermore, I present the results of PSE's backcast of electric and gas sales in the test year, which objectively demonstrates that schedule-level analysis is more accurate. I also address points PSE raised in its rebuttal testimony in the 2017 GRC.

[3] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-170033 & UG-170034, Order 08 (Dec. 5, 2017).

Q. What problems do you see in the Company's electric temperature normalization adjustment?

A. I see two issues. First, the method of allocating the system-level model results into different schedules – in effect, requiring reconciliation of the results of two different sets of models – is problematic. Second, PSE relies on a model with a poor fit for Schedule 29 irrigation customers; the model fails to show a strong correlation between usage and temperature and is therefore of very limited use for normalization.

1. The Two-Model Approach Is Problematic

Q. How does the Company implement its two-model approach?

A. The Company's approach is unnecessarily complicated, requiring two models and three steps.

To arrive at its overall normalizing adjustment, the Company uses the sales adjustment produced by its system-level analysis. So, in the first step, PSE witness Molander develops a system model using daily Generated, Purchased and Interchanged[4] (GPI) system load data and the corresponding daily HDDs and CDDs for each day. Regression models are used to estimate temperature sensitivity coefficients for the entire system.[5] The monthly temperature sensitivity coefficients

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[4] GPI is the total power necessary to meet the load demanded by PSE customers. As the term implies, the power was either generated by PSE power plants, purchased from third parties, or acquired in an exchange with other utilities.

[5] ARMA model stands for Autoregressive Moving Average Model. It is a modification of the ordinary least squared model with autoregressive terms.

are then applied to the deviation of actual temperature from the normal benchmarks as well as the average number of customers in each month in the test year to calculate the adjustment to the electricity system's load and reflect normal weather conditions. The final result is then scaled back by applying a line loss factor to reflect the actual kWh sales to customers.

The Company then allocates this overall system-level sales adjustment to each schedule using the results of a second, schedule-level analysis. Molander develops temperature models for each of the schedules that are deemed temperature sensitive, using daily data for each schedule.

But because the two models produce different estimates for the total sales adjustment, in the third step, PSE witness Molander reconciles the difference in sales adjustment from the system-level model and schedule-level model. Molander does this by allocating the difference to each schedule based on its relative proportion of sales adjustment for the month from the schedule-level analysis.

Q. Do other regulated utilities in Washington utilize a two-model reconciliation approach?

A. No. To my knowledge, Avista Corporation, Cascade Natural Gas Corporation and Northwest Natural Gas Company all use schedule-level temperature normalization.

Q. Why is the Company's two-model approach problematic?

A. PSE's two-model approach attempts to reconcile two separate models that are irreconcilable. The "extra" or "deficient" adjustment produced by the system-level model cannot simply be spread over rate schedules using the schedule-level models. Instead, the schedule-level models produce the *exact* sales adjustment that *belongs* to each weather-sensitive schedule, no more, no less. Any allocation to a schedule beyond what is identified by the schedule-level results is unfair to the customers in the schedule.

The purpose of the temperature models is to develop accurate temperature sensitivity coefficients specific to each customer class in order to calculate each class's usage under normal weather conditions. Staff does not believe the two-model approach, which applies the system model result for the schedule-level adjustment, is appropriate for the following reasons: (1) the average system load per customer is not a good measure for usage patterns; and (2) the allocation to the various schedules is arbitrary.

Q. Why is the average system load per customer not a good measure for usage patterns?

A. PSE's system model uses system Generated, Purchased and Interchanged (GPI) load per customer as the dependent variable. System GPI load per customer is not as meaningful a measure as the usage per customer at the schedule level because the system data reflect aggregated usage from heterogeneous groups and the growth/decline in customer base varies by group over the sampled period. Even though each schedule has small users and large users, the usage per customer pattern is a lot more homogenous. Furthermore, the daily system GPI includes loads for non-temperature sensitive customers, which can skew the system load data.[6] The Company also assumes a constant line loss of 7.1 percent in the system load, but in reality, line loss may not be constant over time. The goal of temperature normalization should be to develop accurate temperature sensitivity coefficients specific to each customer class in order to derive an accurate revenue adjustment. Therefore, while the system model might be useful for system-level forecasting purposes and can serve as a good basic check for the results from the schedule-level models, it is not suited to the temperature normalization adjustment.

Q. Is the Company's allocation to schedules arbitrary?

A. Yes, there is no precise way to allocate the system-level sales adjustment to schedules. As I stated earlier, in an attempt to allocate the system-level sales adjustments to each schedule, the Company relied on schedule-level models to arrive at monthly allocation factors for each heat-sensitive schedule. There is no theoretical basis on which to allocate the difference between system-level adjustment and schedule-level adjustment.

In other words, the Company's system-level model produces a delta that cannot be explained by the schedule-level models. Arbitrarily assigning this sales delta is unfair to classes of customers that, via the schedule specific model, are shown not to have the usage sensitivity the adjustment would imply.

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[6] The schedules that are considered not temperature sensitive are Schedule 35, Schedule 46, Schedule 49 and Schedules 50–59.

Q. What are the causes for the difference in the temperature normalization adjustment in the two models?

A. I believe the difference can be attributed to (1) the modelling errors in both models; and (2) some level of weather sensitivity exhibited by the customers in those schedules that are considered non-weather sensitive.

The first part is inherent in all statistical models. At the total company level, sales adjustments from both models are actually very close. However, the rate schedule level model is more suited for revenue adjustment for rate making purposes because it analyzes the distinct usage patterns for each rate group.

The second reason also makes me favor the rate schedule level adjustment. The Company does not apply temperature normalization to some rate schedules because when analyzed at the rate schedule level, the model results are not statistically significant. Those are usually industrial or large commercial customer groups, interruptible and transportation customer groups whose usage is less influenced by temperature variation. But this is not to say that each individual customer's usage is not correlated by temperature variation at all or does not have a seasonable pattern that coincides with temperature changes. Such usage sensitivity is included in the system-level analysis. However, it would be wrong to allocate the sales delta caused by the non-temperature-sensitive schedules to temperature-sensitive rate schedules. This arbitrary allocation would lead to the inaccuracy of the revenue adjustment to temperature-sensitive rate schedules.

Q. What evidence indicates that the schedule level result is more accurate?

A. I asked the Company to conduct a backcast on the 2018 test year sales applying the coefficients it developed to the actual test year HDDs and CDDs.[7] I present the comparison of the system reconciliation result and the schedule level result in my Exh. JL-8. Overall, the system level reconciliation backcast produced over 2 billion more kWh sales than the actual sales, or 11 percent. The schedule level backcast produced 0.2 billion more kWh sales from the actual sales, or 1 percent. The average absolute deviation percentage from the actual using the system reconciliation approach is 12 percent.[8] The average absolute deviation percentage from the actual using the schedule level analysis is 11 percent, which is an improvement to the system approach. I would also like to point out that the residential schedule backcast sales from the system level reconciliation has a 17 percent deviation from the actual, whereas the rate schedule backcast only has a 7 percent deviation. It supports my belief that the schedule level analysis yields more accurate results in calculating the revenue adjustment.

Q. How do you recommend that the Commission correct the problem you have identified?

A. Since the goal is to identify the proper level of revenue specific to each schedule, emphasis should be placed on getting the schedule-level sales volumes correct. As I have described above, there are several reasons why the system-level models should

[7] PSE Response to UTC Staff Data Request No.82.

[8] I compare the absolute deviation percentage by schedule to evaluate whether or not the prediction is accurate, regardless of the direction of the deviation.

not be used to make schedule-level adjustments. Rather, schedule-level revenue adjustments should be made by using schedule-level temperature normalization models.

Q. Did you read PSE's rebuttal testimony in its 2017 GRC on temperature normalization?

A. Yes. PSE witness Chun Chung sponsored temperature normalization testimony in the 2017 GRC. However, I continue to believe that the temperature normalization adjustment needs to be developed from a schedule level analysis. Chung's rebuttal was centered on the data quality gap between the daily energy use collected for the system and the data collected for rate schedules. He argued that the system data is population data whereas the schedule level data involves sampling for some schedules.

Although I disagree with his justification, I am very impressed by the rigorous steps PSE takes to sample, screen and validate schedule level data. Judging from his regression statistics, the schedule level analysis is sufficiently robust. As in many social-economic studies, a representative sample can be superior to the population data, if the latter is fraught with noise.

2. Electric Schedule 29 should be removed from the temperature-related sales adjustment

Q. What problem does Staff see in the weather normalization adjustment for Schedule 29?

A. The Company reduced the test year sales to Schedule 29 customers by 622,112 kWh, assuming normal weather. Staff believes the adjustment should not be made because the Schedule 29 model has a very poor fit and high degree of forecasting error.

Q. Does the temperature normalization model for Schedule 29 work well?

A. No. Schedule 29 is for seasonal irrigation and drainage pumping service. The customers on this schedule use electricity primarily for agricultural irrigation and water pumping. The correlation between these customers' usage and cooling degree days in the summer is fairly weak. Adjusted R-squared is an accepted, common statistic that is used to evaluate how well a model fits its data. A high adjusted R-squared would indicate a strong correlation between usage and temperature. If a schedule shows an R-squared of 0.90, for example, it would indicate that temperature variation explains 90 percent of the usage variation. The Schedule 29 model has an adjusted R-squared of 0.45. This indicates that the regression model does not support a strong correlation between Schedule 29's usage and temperature. Temperature explains only 45 percent of the usage variation. In other words, non-temperature causes represent the majority of the variation in usage. In comparison, models for other electric schedules usually have an adjusted R-squared well above 0.90.

Q. Did any other statistical measure inform your opinion that the weather model for Schedule 29 is not useful?

A. Yes. Another good reference statistic is mean absolute percent error (MAPE). It represents the average deviation of each observation's predicted value from the actual value. A smaller MAPE indicates greater forecasting accuracy. The MAPE from the Company's model is 89 percent, suggesting a gross amount of prediction error. In comparison, most of the models for the other rate schedules have a MAPE of less than 10 percent. Reliance on a model with a poor fit and high error produces unreliable and inaccurate estimates of usage under normal weather and such models should be rejected.

Q. What other evidence shows that temperature normalization should not be applied to Schedule 29?

A. Based on the Company's backcast, as shown in Exh. JL-8, normalized sales for Schedule 29 are 2,609,334 kWh higher than the actual sales in the test year. This difference represents a 16 percent deviation from the actual sales. The 16 percent deviation indicates a high degree of model inaccuracy. Using the same system reconciliation method that PSE uses for it temperature normalization, the deviation is 27 percent, even higher.

Q. What points did PSE Witness, Chung raise in his rebuttal testimony in the 2017 GRC?

A. He acknowledged that it is a big challenge to develop a good-fit model equation for seasonal irrigation and drainage pumping customers.[9] He believes that the current model PSE uses is ineffective explaining the non-weather related changes in daily energy use per customer for this schedule, such as the non-summer seasonal shut-down and the irrigation energy use for indoor farming.[10] However, he argued that because the t statistics for the temperature variable is statistically significant, temperature normalization adjustment should still be applied to Schedule 29.[11]

Q. Do you agree with his argument?

A. No. As I stated before, a poor model, as reflected in low adjusted R-squared and high error score, is not fit to produce any meaningful forecast. The temperature sensitivity coefficient from this kind of model is biased and unreliable. Applying a sales adjustment will only render a confusing result, as shown in the Company's test year backcast result.

Q. What do you recommend with regard to the Company's adjustment to Schedule 29?

A. I recommend that no temperature normalization adjustment be applied to Schedule 29 for the reasons outlined above.

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[9] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-170033 & UG-170034, Chang, and CKC-3T at 11:11 - 12:4.
[10] *Id.* at 12:6-15.
[11] *Id.* at 13:4 - 14:20.

Q. Please summarize your recommendations for PSE's electric temperature normalization adjustments?

A. I recommend the Commission adopt PSE's schedule-level models and exclude Schedule 29 from temperature normalization. The combined revenue requirement impact from the restating and pro forma temperature normalization adjustments is a reduction of $3,571,400.

B. Staff Analysis of Natural Gas Temperature Normalization Models

Q. Are there problems with the Company's natural gas temperature normalization adjustment?

A. Yes, the same problem I identified in the Company's electric temperature sales adjustment, namely the use of a two-model approach. Earlier, I discussed two reasons why the results from a system-level model are not appropriate for schedule-level adjustments: (1) the average system usage per customer is not a good measure for usage patterns; and (2) allocation to the various schedules is arbitrary.

Q. Please briefly describe PSE's temperature normalization methodology for natural gas service.

A. The Company's natural gas temperature normalization analysis differs from its electric analysis in terms of data sources and model specifications, but the fundamental approach is the same.[12] The Company also applies the three step approach. First, the Company employs three system-level models to develop adjustments for firm, interruptible, and transportation sales, respectively. Second, the Company examines usage sensitivity at the rate class level for each weather-sensitive schedule (commercial and industrial, firm and transportation). In the last step, the Company then reconciles the difference between the results from the system-level analysis and the rate class analysis. The total sales volume adjustment is based on system-level results. The Company's rate class-level analysis resulted in an upward sales adjustment of 53,634,524 therms, compared to the system-level adjustment of 56,683,958 therms.

Q. What is your recommended treatment of PSE's natural gas temperature normalization adjustments?

A. For the reasons I discussed regarding the electric adjustment, in the gas context, I likewise do not recommend using system model results for rate class-level sales adjustments. I recommend the Commission adopt the temperature sensitivity coefficients from the Company's rate class models because they produce more accurate revenue adjustment specific to each rate class. The non-temperature sensitive schedules introduce a lot of "noise" in the system data, particularly in interruptible and transportation schedules.

[12] The Company uses monthly data for rate class-level analysis because daily gas data is not available at the rate class level; and (2) the Company's natural gas rate class models are specified with monthly HDD/CDD variables. The temperature coefficients differentiate heat sensitivity by month.

Q. What evidence demonstrates that the schedule level result is more accurate?

A. Just as in the electric case, I asked the Company to conduct a backcast on the 2018 test year gas sales applying the coefficients it developed to the actual test year HDDs.[13] I present the comparison in my Exh. JL-9. Overall, the system level reconciliation backcast produced sales of about 6 million more therms than the actual sales, or 1 percent. The schedule level backcast produced 29 million fewer therms from the actual sales, or -3 percent. However, this does not mean that the system approach is better. Judging from the average absolute deviation percentage from the actual, schedule level analysis exhibits higher predictive accuracy (4 percent) as compared to the system reconciliation analysis (7 percent). The backcast residential sales from the schedule level has only 1 percent deviation from the actual, whereas the system reconciliation analysis has 3 percent deviation. Once again, for rate making purpose, it is important to establish accurate sales for each schedule in order to properly calculate normalized revenue. Skewed schedule-level revenue also misinforms the cost of service study.

Q. What other problem did you identify while reviewing the temperature normalization adjustment?

A. I have a concern about the inconsistency between the two sales data sets that the Company uses for different purposes. In the Company's restating temperature normalization analysis (temperature normalization adjustment in the 2018 commission basis report), the Company used the sales accounting report from

[13] PSE Response to UTC Staff Data Request No. 83, Attachment A.

Systems, Applications and Products (SAP unbilled sales report), which shows the actual sales for calendar year 2018 of 1,137,939,745 therms. In the Company's pro forma temperature normalization analysis, the Company used the sales report from the Billing System Business Warehouse (BW). The actual sales from BW is 1,135,303,138 therms, 2.6 million therms less compared to the accounting sales report.

The sales volumes from the two reports do not match because they use different methods to derive unbilled usage. Each has its advantages and disadvantages. The accounting sales report provides the unbilled estimates that underlie the revenue report on the income statement but does not provide tier-level details for each rate schedule. The BW report provides estimated unbilled usage at the tier-level based on billing cycle proration, but the total does not match the accounting report. For rate making purposes, I believe we should use the sales report that matches the revenue from the accounting system because we use the revenue and expense from the same system. The matching principle should be upheld.

Q. How do you address the issue you describe above?

A. I propose to use the SAP accounting sales volumes as "actual test year sales" to construct pro forma revenue. I acknowledge that it creates a technical challenge because the 2.6 million therms of sales delta must to be allocated to tiers for each rate schedule. As a quick fix, I used the SAP accounting sales as the actual sales in the temperature normalization adjustment, and the temperature normalized sales flow through the pro forma revenue calculation. In other words, this is a pro forma revenue issue, but it is reflected in the temperature normalization adjustment.

Q. What is your recommended gas temperature normalization adjustment?

A. My modification to the Company's gas temperature normalization is presented as Exh. JL-7. The revenue adjustment is presented as Staff Revised SEF-6.02GE and 6.02GP. My recommendation results in an increase to the Company's gas revenue requirement by $798,500.

V. POWER COST

A. Overview

Q. Please provide a summary of Staff's adjustments to PSE's electric power cost.

A. Staff made a number of adjustments to PSE's proposed power cost for the rate year. Staff witness Gomez addresses the following:

- Removal of Smart Burn rate base and expense (Staff Adjustment 12.01);
- Removal of rate base and expense associated with the 2018 Colstrip outage (Staff Adjustment 12.02 and Revised SEF-7.01 Part A);
- Restoration of wind resource capacity factors in the AURORA model rate year simulation (Revised SEF-7.01 Part G);
- Restoration of PSE's full contracted capacity along the Westcoast gas pipeline used in the forecast of gas optimization revenues (Revised SEF-7.01 Part G); and
- Correction of tariffed rates used in the calculation of gas pipeline transport costs for PSE's gas plants (Revised SEF-7.01 Part G).

I address:

- Removal of Colstrip Unit 4 major maintenance cost for 2020 (Revised SEF-7.01 Part B);
- Removal of common costs allocated to Colstrip Units 3 and 4 as a result of the closure of Units 1 and 2 (Revised SEF-7.01 Part C);
- Recalculation of PSE's equity adder for the Centralia Coal Transition PPA due to changes in the federal tax rate (Revised SEF-7.01 Part D);
- Updating major maintenance cost for Fredonia gas plant (Revised SEF-7.01 Part E);
- Revising the Company's wind facilities' maintenance contract expense and royalties (Revised SEF-7.01 Part F); and
- Restoring 80 separate runs for every year in the water record in the AURORA model (Revised SEF-7.01 Part G).

Q. What is the impact of your adjustment to power cost?

A. Staff's adjustment to SEF-7.01E reduces the Company's power cost by $8,006,108 and reduces revenue requirement by $10,655,129 (restating and pro forma combined).

B. Colstrip Major Maintenance

Q. What is "major maintenance?"

A. Major maintenance, also referred to as an overhaul or major maintenance outage, involves substantial, long-duration maintenance and upgrade work performed at regular intervals, typically once every few years. Major maintenance is distinct from, and more costly than, regular ongoing maintenance.

Q. How is major maintenance cost for generation plant treated in ratemaking?

A. Given that the interval between major maintenance events may be several years, revenue requirement should reflect that the cost does not reoccur annually. For ratemaking, the recovery of major maintenance costs is spread over the interval between major maintenance events. For example, if a steam plant is scheduled for major maintenance every three years, major maintenance cost should be spread over three years.

The all-party settlement in PSE's 2014 Power Cost Only Rate Case (PCORC) specified that major maintenance for Colstrip would be "amortized over the projected time period to the next major event, which is three years, and included in rates based on budgeted expenditures and the estimated timing of the event."[14]

Q. What did PSE propose for Colstrip major maintenance cost in the rate year?

A. PSE's rate year level production O&M expense includes the amortization of the Colstrip Unit 4 major maintenance event scheduled for June of 2020. Colstrip's plant operator, Talen, projects the cost to be [redacted], which PSE proposes to amortize over [redacted] months.[15] PSE includes an annual amortization expense of [redacted]. This is the same approach employed by the Company in the 2017 GRC.

Q. What is your recommendation on the Colstrip major maintenance?

A. I recommend the Commission not include the annual amortization expense of [redacted] in the revenue requirement calculation in this rate case. Instead, the Commission should allow PSE to defer the actual cost when it is incurred and

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[14] *Wash. Utils.& Transp. Comm'n v. Puget Sound Energy*, Docket UE-141141, Order 04, 3, ¶ 8 (Nov. 3, 2014).

[15] All the major maintenance costs mentioned in this section refer to only PSE's share of the costs.

incorporate the annual amortization amount in its next GRC. My adjustment increases NOI by $[redacted] and reduces revenue requirement by $[redacted].

Q. Why do you recommend the Commission change the method approved in the 2014 PCORC?

A. I believe the special circumstances surrounding the aging Colstrip units warrant a deviation from the existing major maintenance normalization method.

Q. What is Staff's concern about including this amortization expense in revenue requirement?

A. Staff is concerned that the projected major maintenance cost is inaccurate and over-estimated, as was the case for PSE's projections of major maintenance costs for Colstrip in its last general rate case. As shown in Exh. JL-10C, the major maintenance costs PSE included in its 2017 GRC turned out to be vastly overestimated. In particular, the Company included an estimated cost of $[redacted] for Colstrip Unit 2 major maintenance in June 2018, but the actual cost was only $[redacted]. Similarly, in the 2017 GRC, the Company included an estimated cost of $[redacted] for Colstrip Unit 1 major maintenance in April 2017, but the actual cost was only $[redacted]. In replying to Staff's inquiry into the variance, in Docket UE-180899 (Expedited Rate Filing), PSE responded, "[A][redacted]

[redacted][16] (Exh. JL-11)

While I do not question that PSE made the prudent decision with regard to Colstrip Units 1 and 2 major maintenance, considering all relevant factors at the time, the magnitude of variance between the budget and actual cost is alarming. As Colstrip Units 3 & 4 age and approach their closure date, and the economics of operating those units become more and more uncertain, it is entirely possible that the scope of the scheduled major maintenance will be scaled back. Staff witness Gomez identifies a major component of the Unit 4 boiler which may need to be replaced next year.[17] If this is the case, it may signal a watershed moment for the continued life of the unit. This lends yet further support to Staff's position on Colstrip major maintenance.

In addition, Talen's budget appears to be tentative. In response to discovery, PSE stated:

> The estimates for years 2020 and beyond will be refined yearly as the budget cycles get closer to the year of actual work and more information is obtained. Additionally, the scope of the outages can change once hands-on work is begun and the needs of the unit can be established.[18]

In a separate response, the Company stated, "Additionally, the 2020 budget for Colstrip is still under consideration by the co-owners and is not yet finalized."[19]

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[16] See Exh. JL-11, PSE's Response to UTC Staff Data Request No. 168.
[17] Gomez, Exh. DCG-1CT at 25:19 - 26:19.
[18] See Exh. JL-12C, PSE Response to UTC Staff Data Request No. 93 (C).
[19] See Exh. JL-13C, PSE Response to UTC Staff Data Request No. 75 (C), Ronald Roberts' Response Subpart G.

While Staff has asked PSE to provide a final Talen budget when it becomes available, a final budget has yet to materialize.[20]

Q. Why do you recommend that the Commission allow PSE to defer the 2020 Colstrip major maintenance cost?

A. Although PSE's projections are not reliable estimates of its actual costs, I acknowledge that PSE is likely to incur some level of major maintenance expense for Colstrip Unit 4 in 2020, even if it is decided that the repairs required to the boiler result in retirement of the unit. Therefore, my proposal provides PSE with an opportunity to recover those costs at a later date.

Deferred accounting provides flexibility to accommodate changes in the scope, timing and cost of the major maintenance event in question, especially given Staff's concern over continued operation of Unit 4. Importantly, in addition to allowing the Company an opportunity to recover the actual maintenance expense, deferred accounting protects rate payers from the risk that their rates will include projected costs out of step with the major maintenance costs that the Company will actually incur. This is a very real risk with Colstrip major maintenance, as evidenced by the projected costs from PSE's 2017 GRC, which were [redacted] percent over the actual costs.

[20] PSE Response to UTC Staff Data Request No. 165.

C. Colstrip O&M – Common costs allocated to Colstrip Units 3 and 4

Q. How does PSE propose to reallocate common costs to Colstrip Units 3 and 4, given that Units 1 and 2 will be removed from service?

A. PSE proposes to allocate to Colstrip Units 3 and 4 one-half of the common O&M costs currently allocated to Colstrip Units 1 and 2. PSE estimates and requests recovery of an additional [redacted] in O&M expense for Units 3 and 4, related to common costs previously allocated to Units 1 and 2. PSE witness Roberts explains:

> The common facilities agreement covering O&M costs common to all units will terminate, and all of the common O&M costs would be charged to Colstrip Units 3 & 4. PSE's ownership share of Colstrip Units 1 & 2 is 50 percent (as compared to 25 percent for Colstrip Units 3 & 4); accordingly, only one half of the selected common facilities O&M charged to Colstrip Units 1 & 2 in the test year were added as an adjustment to O&M costs for Colstrip Units 3 & 4 for the test year.[21]

In other words, PSE assumes the common costs pertaining to all Colstrip units will remain unchanged after Units 1 and 2 are removed from service, and so the portion of common costs currently allocated to Units 1 and 2 will have to be reallocated to Units 3 and 4 and recovered from ratepayers.

Q. What is your recommendation?

A. I recommend that the Commission not include in rates common costs for Colstrip Units 1 and 2 that PSE shifts into the pro forma O&M expense for Units 3 and 4. The Commission should use the test year O&M expense for Colstrip Units 3 and 4,

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[21] Exh. RJR-1T at 27:5-13.

adjusted by the amortization of major maintenance cost, but allow no additional increase based on a hypothetical change in cost allocation among units. Staff's adjustment increases the Company's NOI by $[redacted] and reduces revenue requirement by $[redacted].

Q. What is the reason for your recommendation?

A. PSE's increase in O&M expense for Units 3 and 4 does not meet the Commission's rules on pro forma adjustments; the costs are neither known nor measurable, and the proposed increase is likely to be offset by other factors, which PSE does not address. PSE's adjustment should be rejected in full.

Q. Why do you believe the additional O&M is <u>not</u> sufficiently known and measurable?

A. Based on the Commission's rule, any pro forma adjustment needs to meet the "known and measurable" standard:

> Pro forma adjustments give effect for the test period to all known and measurable changes that are not offset by other factors. The company and any other party filing testimony and exhibits proposing pro forma adjustments must identify dollar values and underlying reasons for each proposed pro forma adjustment. Pro forma adjustments must be calculated based on the restated operating results. Pro forma fixed and variable power costs, net of power sales, may be calculated directly based either on test year normalized demand and energy load, or on the future rate year demand and energy load factored back to test year loads. [22]

[22] WAC 480-07-510(3)(c)(ii).

PSE does not have a firm estimate for O&M expense for Colstrip Units 3 and 4 at this time. In its initial filing, PSE used the common cost allocated to Colstrip Units 1 and 2 in the 2018 test year, and transferred that amount to Colstrip Units 3 and 4 dollar for dollar. The Company explained, "At the time of the original filing, the announcement to retire Colstrip Units 1 & 2 had just been made. Therefore, absent a known budget for post-closure common costs, PSE used test year common costs for its estimate of the costs to be allocated to Colstrip Units 3 & 4 of which PSE would be responsible for 25 percent of those charges in accordance with its Colstrip Units 3 & 4 ownership share."[23]

I reviewed all items that PSE listed for Colstrip common O&M costs in PSE witness Roberts' workpaper.[24] I question why many of the costs currently allocated to Colstrip Units 1 and 2 would not be reduced or completely go away upon closure of the units (for example, general maintenance cost), or continue to be allocated to Units 1 and 2 in the rate year as decommissioning and remediation costs, which will be recovered through a separate arrangement (for example, roads and grounds).[25]

Further, with its proposed adjustment, PSE assumes that the increase in costs associated with the re-allocation of the common costs for Units 1 and 2 will not be offset by cost reductions elsewhere, even though it is reasonable that a company

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[23] See Exh. JL-14C, PSE Response to UTC Staff Data Request No. 121 (C).

[24] PSE Workpaper "RJR_WB_C_2019_GRC_Production_OM_Workpaper_Rvn17Apr(C)," tab "Common Costs U1&2 (C)."

[25] PSE confirmed this understanding in its response to UTC Staff Data Request No. 121: "Amounts provided by Talen for 2020 and 2021 that have been assigned to Colstrip Units 1 & 2 would likely be charged against the retirement account established pursuant to Chapter 80.84 RCW, which is funded by hydro-related Treasury Grants."

would reduce its maintenance expenses for a facility approaching retirement, such as Units 3 and 4.

Upon further inquiry, PSE provided additional details from Talen MT's budget for the rate year. [26] However, the new information is even more confusing. The Company states that Talen was unable to determine how the original information was compiled. Talen recompiled the information and provided a different amount of O&M expense for Colstrip Units 3 and 4 based on a new re-allocation of common cost.[27] It further illustrates the uncertainty Talen and PSE have about the Colstrip rate year O&M.. As I pointed out earlier in my testimony, Talen's budget for all Colstrip units is not final; Talen's planned common cost reallocation among units is not final. PSE stated the following in its response:

> Talen MT and PSE are continuing to research and identify which activities will need to be supported in 2020 to bring Units 1 & 2 to a cold, dark, dry and safe condition. Work has progressed significantly but is not fully finalized; a full plan is anticipated by the end of 2019.[28]

The rate year O&M for Units 3 and 4 is simply not measurable.

Q. Will you recommend adopting the Talen budget for Colstrip O&M if the budget is finalized and presented in the record in December 2019?

A. No. As discussed above, PSE's proposed increase to O&M expense for Units 3 and 4 does not meet the Commission's rules regarding pro forma adjustments. A new budget from Talen does not cure this issue. For a pro forma adjustment to be

[26] See Exh. JL-14C, PSE Response to UTC Staff Data Request No. 121 (C).
[27] *Id.*
[28] *Id.*

measurable, a budget amount usually does not suffice. The Commission provided guidance in PSE's 2009 GRC:

> Furthermore, the actual amount of the change must be measurable. This means the amount typically cannot be an estimate, a projection, the product of a budget forecast, or some similar exercise of judgment – even informed judgment – concerning future revenue, expense or rate base.[29]

The Commission should also be aware that Talen has consistently over-estimated the Colstrip O&M budget in the past. Please refer to my Exh. JL-15C for a comparison of budget, actual cost, and the cost built into GRC rates between 2013 and 2018. With a few exceptions, the budgeted expense is higher than the actual expense year after year. The variance is very pronounced in 2017 and 2018. When such budget amounts were adopted in the GRCs, the cost built into the rates was too high, and the ratepayers over paid by millions.

Q. Has the variance between budgeted and actual costs been an issue in the past?

A. Yes. In Docket UE-130617, the Commission approved the settlement agreement which removed $1 million related to Colstrip O&M expense. The Commission stated,

> We note that ICNU's Exhibit No. DWS-3 shows that, from 2009 to 2012, PSE budgeted between 2.0 percent and 11.6 percent more for Colstrip O&M expenses than it actually incurred, with an annual average of $2.7 million more budgeted than actual expenses. It is not unusual for a company's filed budget to vary from its actual expenses for a particular generating station. We note that this variation is expected whether the difference results in overstatements or understatements of cost. Here, however, several years of

[29] *Wash. Utils.& Transp. Comm'n v. Puget Sound Energy*, Dockets UE-090704 and UG-090705, Order 11, 12, ¶ 26 (April 2, 2010) (PSE 2009 GRC Order).

> filed data show only overstatement of costs; thus, we find the Settlement's inclusion of this adjustment reasonable and in the public interest.[30]

Q. Do you recommend a reduction to Colstrip O&M in the rate year?

A. No. I expect PSE and other owners of Colstrip Units 3 and 4 to prudently manage the O&M costs as the units approach retirement. However, I do not have information to adjust Colstrip O&M up or down. Using the test year O&M amount may be a stretch, but that is the best information available.

Q. Could you summarize your findings and recommendation on this issue?

A. With its proposed adjustment, PSE asks that all common costs previously allocated to Units 1 and 2 be reallocated to Units 3 and 4, even though Units 1 and 2 will continue to rely on common facilities after closure. In the absence of a reliable budget from the Colstrip operator, I find the rate year O&M expense for Colstrip Units 3 and 4 is not sufficiently measurable. I recommend the Commission remove any estimated additional O&M beyond the test year level for Colstrip Units 3 and 4.

D. Centralia Power Purchase Agreement (PPA) Equity Adder

Q. Please explain the Centralia PPA equity adder.

[30] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-130617, Order 06,8-9, ¶ 22 (Oct. 23, 2013).

A. In 2013, the Commission approved a power purchase agreement between PSE and TransAlta Centralia Generation LLC that provides for PSE's purchase of an average 346 MW of coal transition power, as defined in RCW 80.80.010, over a contract term of 133 months, from December 2014 to December 2025.[31] The Commission determined that, in addition to the cost of power, PSE is authorized by statute to recover an allowed return on the PPA at PSE's pre-tax weighted average cost of equity.[32]

The inclusion of an equity adder is a unique feature of the Centralia Coal Transition Power Purchase Agreement and does not apply to "any other power purchase agreement or other power contract."[33]

Q. How is the equity adder calculated?

A. As provided in RCW 80.04.570(4), PSE is allowed to earn the equity component of its authorized rate of return in the same manner as if it had purchased or built an equivalent plant. The Commission found that the equity adder should be based on a hypothetical "equivalent plant" cost of $110 million.[34] The Commission also accepted PSE's proposed method of calculating the equity adder, which calculated at the outset the full amount of return it will be allowed to recover over the life of the

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[31] *In Re Petition of Puget Sound Energy, Inc., for Approval of a Power Purchase Agreement for Acquisition of Coal Transition Power, as Defined in RCW 80.80.010, and the Recovery of Related Acquisition Costs*, Docket UE-121373, Order 03 (Jan. 9, 2013) (Centralia PPA Order).

[32] *Id.*

[33] *Id.* at 7, ¶ 13. Also see *RCW 80.04.570(8).*

[34] *Id.* at 5, ¶ 8.

Coal Transition PPA and provide for recovery of the total amount on a levelized basis over the term of the contract.[35] The Commission determined that it is appropriate in this unique situation to fix the allowed return on the Coal Transition PPA at PSE's authorized pre-tax weighted average cost of equity at the time: 7.24 percent. As a result, PSE is authorized to receive a levelized equity adder of $1.49 per MWh for all deliveries of power under the contract.[36]

Q. What is the impact to power cost expense of PSE's current Centralia PPA equity adder?

A. The Company calculated the equity adder amount by multiplying the PPA quantity by $1.49/MWh which, for the rate year, results in $4,959,912 of power cost expense ($4,733,258 after applying the production factor).

Q. What is the problem with PSE's calculation?

A. PSE continues to calculate the equity adder as if tax reform never happened. More specifically, PSE's requested equity adder of $1.49 per MWh is based on a federal corporate tax rate of 35 percent.

Q. What is your recommendation?

A. I recommend the Commission reduce the equity adder to $1.23/MWh to recognize the reduction of the federal income tax rate from 35 percent to 21 percent, based on the Tax Cuts and Jobs Act of 2017 (TCJA). Keeping the authorized return on equity

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[35] *Id*. at 21, ¶ 49.
[36] *Id*. at 46, ¶ 123.

(9.8 percent) and equity ratio (48.0 percent) the same, PSE's authorized pre-tax weighted average cost of equity has changed from 7.24 percent to 5.95 percent. I provide my calculation for the revised equity adder in Exh. JL-16.

After adjusting for the revised corporate income tax rate, the equity adder for PSE is $4,094,424 ($3,907,320 after applying the production factor). My adjustment increases net operating income by $652,491 and reduces the revenue requirement by $868,389.

Q. Is your recommendation consistent with the Commission's decision in the Centralia PPA order?

A. Yes. In the Centralia PPA Order, the Commission made a point to discuss the potential need for an adjustment to the equity adder in the event that there is a change in the federal corporate income tax rate:

> There is a second factor to consider in this connection, though it was not addressed explicitly by the parties. This is the question of income tax effect. The 7.24 percent pre-tax weighted average cost of equity is calculated using PSE's currently authorized rate of return on equity of 9.8 percent, its currently authorized equity share in the Company's capital structure of 48 percent and the currently effective federal corporate income tax rate of 35 percent. The formula is: (9.8% x 48%)/65% = 7.24%. While we determine PSE's authorized rate of return on equity in general rate cases we have no control over the federal income tax rate. <u>PSE is at risk if the corporate income tax rate increases. Ratepayers are at risk if it decreases. Should the corporate income tax rate change during the term of the Coal Transition PPA, the Commission may consider in an appropriate case whether the equity adder should be adjusted to reflect the new rate</u>.[37]

[37] Centralia PPA Order at 21, ¶ 50 (emphasis added).

In authorizing the equity adder of $1.49 per MWh, the Commission further stated that:

> Using the method we approve, coupled with our decisions on the cost equivalent plant and equity return, results in an equity adder of $1.49 per MWh, <u>assuming no change is required in the future due to a change in the federal corporate income tax rate</u>."[38]

The Commission was clear when it identified income taxes as a critical element in the calculation, and it indicated that a change to the corporate tax rate was the one factor that could necessitate an adjustment to the equity adder.

On January 1, 2018, a new federal corporate tax rate went into effect. Accordingly, the current case constitutes "an appropriate case" for "consider[ing] <u>whether the equity adder should be adjusted to reflect the new rate</u>."[39] Such an adjustment is consistent with the Commission's decisions on other rate changes and refunds necessitated by the TCJA, which consistently require that the tax cut savings be passed on to customers.[40]

Q. Do you propose to modify other components of the Centralia PPA equity adder calculation?

A. No. My revision to the equity adder is strictly limited to the correction of the federal income tax rate. All other elements of the calculation remain the same including the embedded equity return at 9.8 percent. This approach preserves the simplicity of the

[38] *Id.* at 23, ¶ 57 (emphasis added).
[39] *Id.* at 21, ¶ 50.
[40] Commission news release titled "State regulators: Utilities must pass federal tax cut savings on to customers," available at https://www.utc.wa.gov/aboutUs/Lists/News/DispForm.aspx?ID=495.

up-front calculation that PSE advocated for and the Commission accepted in Docket UE-121373.[41]

Q. Are you recommending that the Commission order PSE to refund amounts collected from customers between January 1, 2018, and April 30, 2020, when the corporate tax rate was 21 percent but the equity adder continued to be based on a 35 percent rate?

A. No. The Commission's Centralia PPA Order contemplates the need to modify the equity adder in the event of a change to the federal corporate tax rate, and it suggests that it would do so in an "appropriate case." Staff interprets the Commission's language to mean the modification would be made within a case that would set forth prospective rates. The appropriate case is this one, where the Commission will determine the equity adder it will provide the Company in the rate year.

Moreover, while the equity adder uses the federal tax rate as an element of the calculation, the $1.49 per MWh was an amount provided at the Commission's discretion using whatever approach it deemed appropriate at the time. It is not necessary or even appropriate to revisit such a discretionary decision. However, Staff believes that given the change in the corporate tax rate, it is appropriate for the Commission to consider whether the equity adder should be revised going forward to reflect the benefits of a lower corporate tax rate, especially given that the Commission called this issue out specifically.

[41] Centralia PPA Order 03 at 22-24, ¶¶ 51-57.

E. AURORA Power Cost Model – Single Run versus 80 Runs

Q. Please summarize the Company's proposal with regard to the AURORA power cost model and Staff's positions.

A. PSE's power cost witness, Paul Wetherbee, details the specific changes in both the AURORA modeling methodology and the assumptions that the Company relies on to arrive at its level of power costs for the rate year.[42] Staff contests the following changes proposed by PSE in this case:

AURORA model rate year simulation:

- A single model run using an average of the full 80-year water record as opposed to 80 separate model runs (one for each year of the water record); and
- Derate of wind capacity factors.

Outside Model Adjustments:

- Derate of the capacity of PSE's Westcoast gas pipeline resource in calculating gas optimization revenues; and
- Correction of erroneous fixed pipeline rates on Cascade Natural Gas's transmission tariff (includes changes reflecting new Federal tax rates).

Q. What is Staff's recommended variable power cost from the AURORA model?

A. Incorporating Staff's recommendations on using the average power cost from 80 model runs, higher wind capacity factors, full Westcoast gas pipeline capacity for optimization, and updating Cascade pipeline rates, Staff recommends $734.99

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[42] Wetherbee, Exh. PKW-1CT at 48-82.

million in total rate year variable power costs, $8.52 million less than the Company's proposal. The variable power cost result is set forth in my Exh. JL-17C.

Q. What is your position on the Company's proposal of using a single AURORA model run with average hydro generation?

A. I do not support this approach. I believe it distorts the results from the AURORA model rate year simulation, effectively re-introducing a hydro normalization controversy to power costs, which the Commission previously addressed in Order 11 in PSE's 2009 GRC.[43] In the 2009 GRC, the Commission rejected arguments from Staff and another party who advocated for a hydro normalization approach. PSE's proposal in this GRC suffers from the same malady. Furthermore, PSE's proposal offers no analysis of how those probability distributions affect the sharing of risks and benefits accomplished by the PCA sharing bands.

Therefore, I recommend the Commission require the Company to restore its existing practice of running the AURORA model for each year of the available hydro record (80 hydro years in this GRC) and average the power costs from all runs to estimate rate year power cost. In other words, I recommend we average the power cost output from AURORA model runs rather than averaging the hydro input in AURORA model.

Q. What is the effect of using a single run on variable power cost from AURORA?

[43] PSE 2009 GRC Order at ¶¶ 113-125.

A. PSE witness Wetherbee stated a single run method reduces the rate year variable power cost by $6.2 million.[44]

Q. What is the Company's justification for a single run result?

A. The Company's main justification is computational simplicity, not results. Wetherbee stated:

> As indicated above, power costs continue to be projected using estimates of 80 years' worth of hydroelectric generation, which are based on 80 years of actual streamflow data. Historically, PSE interpreted this requirement by running AURORA 80 times, one for each year of hydro generation, and taking the average of power costs that resulted from these 80 runs. <u>This is a time consuming process that requires significant computational power</u> [emphasis added by Staff]. In this proceeding PSE proposes to modify its interpretation of 80-year hydro to averaging the input to AURORA, running the model once using that average hydro as an input, and using the power costs that result from that run rather than averaging the output of 80 runs.

According to the Company, using the existing method of averaging power cost takes about 14 hours of computational time for AURORA to complete 80 runs, on a desktop computer devoted exclusively to running the simulation. An analyst then has to spend a substantial amount of time to manually extract and process the data to calculate power cost.[45] Weatherbee stated that "[r]educing the number of AURORA runs not only reduces the computational time, it reduces the manual labor required to extract and process the output data. The power of the computing

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[44] Wetherbee, Exh. PKW-1CT at 62, Table 11. This comparison is based on PSE's input assumptions.
[45] *Id*. at 60:13 - 61:2.

resources used impacts both computational time and the analyst's efficiency in processing the output data."[46]

Q. Please explain why you do not support of the power cost result from a single run.

A. While computational simplicity is an important consideration, model forecast accuracy should not be sacrificed for the sake of simplicity. As I stated before, a single model run based on average hydro generation from the 80-year record does not produce the same result as 80-separate model runs. In PSE's 2009 GRC, the Commission acknowledged that market prices and the Company's total resource costs do not respond to hydro conditions in a symmetrically proportionate fashion. In general, everything else equal, when hydro is abundant, market prices will be low and PSE's resource costs will be relatively low; when hydro condition is poor, market prices will be high and PSE's resource costs will be relatively high. However, the magnitude of the downward impact from good hydro conditions on PSE's power costs in the first scenario outweighs the magnitude of the upward impact from poor hydro conditions in the second scenario, due to PSE's resource position. The current design of the PCA sharing bands are based on this observed asymmetrical relationship between hydro conditions and power costs[47] and therefore,

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[46] *Id.*

[47] In the current PCA design, the costs and benefits of power cost variances are shared between PSE and customers according to three graduated levels of power cost variance, or sharing bands. The dead band includes the first $17 million of power cost variance (+/-). Within the dead band 100% of costs and benefits are retained by PSE. The first sharing band includes power cost variances between $17 and $40 million (+/-).

any proposal to modify the established procedures for hydro normalization needs to be supported by analysis which acknowledges this reality.

Q. How does the company explain the reason for the asymmetrical impact from hydro variations?

A. The Company provided its analysis of the cause in response to UTC Data Request No. 202 (Exh. JL-18C). The Company believes that the high hydro generation leads to artificially high reduction to PSE's resource cost because AURORA violates the hydro resources' capacity constraints during on-peak hours. The Company explains:

> Because AURORA avoids dispatching a resource at less than its marginal cost, it will not generate a negative market energy price,[1] effectively imposing an artificial price floor. In order to do this while still matching total generation to input hydro volumes, AURORA must at times relax certain model constraints—specifically, the maximum capacities of certain hydro resources. The model's imposition of a price floor and violation of hydro capacity constraints cause resource costs to be lower than they otherwise would be.
>
> The model enforces its price floor by reducing hydro generation during off-peak hours, when prices and loads are already low, and shifting that generation to on-peak hours, when prices and loads are higher. This results in on-peak hours during which AURORA generation for a specific hydro resource exceeds the resource's maximum capacity. By relaxing the capacity constraints during on-peak hours, AURORA is able to reduce hydro generation in off-peak hours, resulting in artificially high system prices that, without violating constraints, would be lower or negative. PSE's portfolio frequently sells excess energy to the market during off-peak hours, especially during periods of high hydro production. When those sales are valued at the artificially high off-peak price, total resource cost results are unrealistically low. Conversely, higher hydro generation in on-peak hours results in prices that are artificially low during those periods. PSE's portfolio frequently

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Within this band costs are shared 50 percent to PSE and 50 percent to customers, while benefits are shared 35 percent to PSE and 65 percent to customers. The second sharing band includes power cost variances over $40 million (+/-). Costs and benefits in this band are shared 10 percent to PSE and 90 percent to customers.

> purchases energy from the market during on-peak periods. When those purchases are valued at the artificially low on-peak price, total resource costs are again unrealistically low.[48]

Q. Did the Company quantify the impact from such capacity constraint violation?

A. No. The Company provided only an example contrasting Mid-C Rocky Reach generation from AURORA run based on 1929 hydro record (low hydro), 1997 hydro record (high hydro) and average hydro condition from 1929 to 2008. According to the Company, capacity limits were violated 750 times per run, or 1.7 percent of hours for five Mid-Columbia hydroelectric projects.

Q. Do you believe the capacity constraint violation is the sole source and the major source for the difference between the single run and 80 run results?

A. No. The Company simply provided the validation that the power cost distribution is not symmetrical to the hydro distribution. Because PSE frequently sells excess power during off-peak hours, especially when hydro is abundant, good hydro conditions reduce its resource cost but the influence is mild due to low off-peak price. On the other hand, PSE frequently buys power during on-peak hours when it needs to meet the demand. When hydro generation is low, on-peak market prices will be even higher than normal. As result, PSE's resource cost will be negatively affected by a large degree. The result from AURORA simulation reflects the reality.

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[48] Liu, Exh. JL-18 (footnote omitted).

Besides, the Company failed to establish the alleged AURORA's hydro capacity violation leads to material difference in power cost. Wetherbee provided a table comparing AURORA results using a single run or 70/80 runs.[49] The table shows the single run and 70 run produce very little difference in 2014 PCORC result and 2016 Power Cost Update, using 1929-1998 hydro records. If the Company's alleged capacity violation is true, the effect of such violation would manifest in these two cases as well. It appears that the inclusion of the hydro records during 1999-2008 created a difference in power cost between the single run and 80 run results.

Q. Should the Company include the hydro data from 1999 to 2008?

A Yes. It is the Commission's long-standing preference to use the longest span of years possible.[50]

Q. Is the asymmetric distribution of power cost in relation to hydro conditions a new issue?

A. No, it is not. PSE's proposal of using the average hydro input is very much akin to the hydro filtering issue that parties debated in the 2009 GRC.[51] In that case, the Industrial Customers of Northwest Utilities (ICNU) and Commission Staff proposed to apply a filter to exclude from AURORA the water years that fall outside of one standard deviation above and below the mean water year in the 50-year record

[49]Wetherbee, Exh. PKW-1CT at 62, Table 11.
[50] PSE 2009 GRC Order at ¶ 125.
[51] PSE 2009 GRC Order.

on which PSE relied.[52] The Company's witnesses Mills and Dr. Dubin, strongly critiqued and objected to the hydro filtering from a statistical and analytical perspective.[53] The Commission ruled in favor of the Company on this issue, stating that the filter proposal is not justified.

The Commission stated:

> Specifically, [ICNU/Staff] miss the point that <u>while hydrologic data may be normally distributed, these data are strongly correlated with power costs which were not normally distributed</u> in the case of PacifiCorp and may not be normally distributed in PSE's case either… <u>While it is true that removing both high and low values from the normally distributed water record will not significantly bias the average water year, it did, in the case of PacifiCorp, bias the average power cost</u>.[54] Since the purpose of calculating a normalized power cost is to estimate the expected value (*i.e.,* the average) of power costs, the Commission found that the one-standard deviation method was flawed and actually favored a different, less biased, statistical method offered by PacifiCorp in that case.[55]

The Commission further stated, "ICNU/Staff have neither offered any analysis of the probability distribution of power costs nor shown how that distribution is related to the probability distribution of hydrologic data."[56]

Q. Why is the Company's proposal of hydro averaging similar to hydro filtering issue raised in the 2009 GRC?

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[52] *Id*. See discussion in ¶¶ 102 - 118.
[53] *Id*.
[54] Indeed, if simply filtering water-years were enough to address the concerns raised in our PacifiCorp order, there would be no reason to use multiple water years at all. The average water year would suffice. We find value in the using AURORA with a full distribution of water records because the modeled results capture the way the water conditions interact with other factors affecting power costs.
[55] PSE 2009 GRC Order at 44, ¶ 115 (emphasis added).
[56] *Id*. at 44, ¶ 116.

A. Setting aside the statistical rigor in ICNU/Staff's proposal at the time, ICNU/Staff's intent of hydro filtering was to remove outliers in water years so the hydro input in AURORA model would more closely resemble the mean/average hydro year. In this GRC, the Company proposed to run AURORA a single time using the average hydro condition, jumping from hydro filtering straight to hydro averaging. By averaging the hydro input, the Company excluded the power cost variance from extremely high or extremely low hydro conditions. Ironically, it is the exact opposite of the Company's position in 2009 GRC, in which it argued against the removal of outliers. In the 2009 GRC, PSE witness Mills argued that the distribution of power cots is skewed across various hydro condition.[57] The Commission agreed with this argument and acknowledged that power costs may not be normally distributed. In this GRC, the Company's use of a single run substituted the averaged power costs from 80 hydro conditions with power cost from the average hydro input, ignoring the distribution of power costs across 80 runs.

Q. Did the Company provide any analysis of the probability distribution of power costs and show how that distribution is related to the probability distribution of hydrologic data in this case?

A. No.

Q. Please summarize your conclusion on the single run versus 80 run issue.

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[57] *Id*. at 41, ¶ 108.

A. I recommend the Commission continue the practice of estimating rate year power cost based on average AURORA power cost output from 80 runs, not based on average hydro input. The Company raised a point about AURORA's violation of hydro capacity constraint even though I do not believe the effect of the violation explains the $6.2 million difference in power cost.

F. Other Power Cost Related Issues

Q. Please briefly discuss other power cost related adjustments and issues.

A. My other power cost adjustments are relatively minor and related to the other power cost adjustments.

I made a small adjustment to reflect the actual major inspection cost for Fredonia gas generation plant.[58] It increases the normalized production O&M by $[redacted] and increases the electric revenue requirement by $[redacted].

I revised the wind resource maintenance contract cost and royalties because they are calculated based on the rate year wind generation. Gomez recommends the Company restore the capacity factors for wind resources in the AURORA model agreed to in the 2017 GRC. The recommendation increases wind generation and, in turn, increases the maintenance and royalties expense. My adjustment increases the production O&M by $[redacted] and increases the electric revenue requirement by $[redacted].

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[58] PSE Response to UTC Staff Data Request No. 166(C).

I revised PSE Adjustment 7.02EP Montana Energy Tax. The tax amount is calculated based on Colstrip generation level in the rate year. Because Staff proposed modification to the Company's variable power cost, the Montana Energy Tax has a small change. This adjustment increases the NOI by $[redacted] and reduces electric revenue requirement by $[redacted] .

Q. Do you have other statements?

A. Yes. I have a few words about Green Direct. Staff witness Kathi Scanlan provides an in-depth discussion regarding the Company's Green Direct Program. In the context of the rate year power cost estimate, I do not contest the inclusion of the new wind and solar contracts the Company secured for the Green Direct Program in this GRC. Subscribers of the Green Direct Program remain PSE's customers and continue to contribute to the recovery of the non-energy portion of the power cost. The new wind and solar contracts are part of PSE's power supply portfolio.

Furthermore, the cost and benefit of the Green Direct resources are intertwined with the rest of the system resources. When the Green Direct resources under-produce, these customers will need to take energy from the rest of PSE's power resources; when the Green Direct resources over-produce, other rate payers will need to absorb the excess energy. The imbalance calculation boils down to the difference between the Green Direct contract price and the cost of system power at the times of over-production or under-production.

I echo Scanlan's concern about the tracking of revenue and cost associated with the Green Direct Program. The logistical complexity should not be overlooked.

I agree with Scanlan's recommendation that the Commission should require the Company to work with Staff and other interested stakeholders to develop a satisfactory plan to accurately track the imbalance of revenue and cost associated with the Green Direct resources to ensure that general rate payers do not cross-subsidize Green Direct customers, or the other way around.

VI. STAFF'S ATTRITION ANALYSIS

A. Summary of Staff's Attrition Analysis

Q. What are the results of your attrition analyses?

A. My analysis, like PSE's analysis, relies on statistical extrapolations to project rate year costs. Relative to Staff's pro forma revenue recommendation, my attrition analysis suggests a rate year revenue *sufficiency* of $~~3.9~~2.5 million for electric operations and a rate year revenue deficiency of $~~9.4~~12.1 million for natural gas operations. My attrition analysis produces revenue requirements that are reasonably close to Staff's pro forma revenue requirements.

I present the results of my electric and gas attrition analyses in Exh. JL-19. I also present a comparison between my attrition base and growth factors and PSE's in Exh. JL-20.

Q. Based on the results of your attrition analyses, do you incorporate attrition allowances into your electric and natural gas revenue requirement calculations?

A. No. Staff believes the pro forma case more accurately reflects the verifiable revenue, expense and rate base in the modified historical test year. The attrition study relies on forecasted rate base associated with Advanced Metering Infrastructure (AMI) and Get-to-Zero (GTZ) as well as statistical trending of gross plant and expenses, creating challenges for Staff to adhere to our long-held "used and useful" and "known and measurable" principles.

Q. Should the Commission authorize revenues using the results of PSE's attrition studies?

A. No. PSE's attrition analyses use an exponential growth model to project rate year rate base, which assumes that the growth will accelerate between the test year and the rate year. Some of the growth factors PSE witness Amen developed were based on combined categories, inflating the overall growth. In addition, ~~in~~ PSE witness Amen's regression models~~, historical data were used without excluding~~included two large capital projects that should have been excluded.

B. Overview of Staff's Attrition Analysis

Q. What is "attrition"?

A. As Staff witness McGuire explains, in a utility rate making context, if utility costs are rising more rapidly than revenues, causing test period relationships to not hold into the rate-effective period, the resulting erosion of earnings is referred to as earnings "attrition."

Q. What is an attrition study?

A. An attrition study is an analysis that measures rates of growth in utility costs and revenues, and assesses the extent to which, or whether, differential rates of growth are likely to cause an erosion of earnings during the rate-effective period. The results of an attrition study are typically compared to revenues produced using a standard pro forma ratemaking approach to assess whether the standard ratemaking approach is likely to produce revenues sufficient to cover the utility's cost, including a reasonable return on rate base. Regression models often are used to develop escalation factors that produce projections of future costs.

Q. What is your general assessment of PSE's attrition study?

A. I find PSE's basic analytical framework reasonable. However, as I describe in detail below, I contest certain elements of the Company's methodology. In my analysis, I modified PSE's base year level of expense and rate base and I revised the Company's attrition growth factors.

Q. What do you like about PSE's attrition study?

A. PSE developed a rather sophisticated framework to analyze the growth trend of plant in service and expense categories.[59] For rate base, PSE analyzes the gross plant in each functional category (production, transmission, distribution, general, and intangible) separately. Depreciation expense, federal income tax, accumulated depreciation, and accumulated deferred federal income tax are calculated separately

[59] *See* Amen, Exh. RJA-1T, Table 1, for an illustration of PSE's methodological approach.

by PSE witness Marcelia. PSE also separately analyzes the trend in each non-depreciation/amortization expense category. Furthermore, PSE isolated the known impact from large investments such as AMI, GTZ, and gas pipeline replacements covered in the Cost Recovery Mechanism (CRM). Future revenue is projected based on existing rates and forecasted load and number of customers in the rate year.

All in all, this is a more fine-tuned attrition study than what other utilities have presented to the Commission before. PSE's attrition model has a number of advantages. First, since depreciation/amortization expense is the largest category of all expenses, forecasting depreciation/amortization expense based on plant additions yields more precision in predicting this expense. Second, the incorporation of budgets for large projects in the immediate rate year provides more insights about the drivers of rate base escalation. Setting aside the precision of the budget, this step is a big improvement from a simple trending practice of net plant in service.

Q. What are the shortcomings of PSE's attrition study?

A. Fundamentally, PSE's approach requires Staff to assume that historical growth in costs tells us fairly precisely how costs will grow into the future. However, as the Commission has recognized, statistical extrapolations from historical data tell us very little about actual costs or business decisions driving those costs.[60] Historical trends do not guarantee that future costs will materialize.

Q. Does an attrition study always generate an upward attrition allowance?

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[60] *Id*. at ¶ 71.

A. No, not necessarily. The attrition analysis examines the relationship between revenue, expense and rate base and judges revenue deficiency using the same formula as in a pro forma rate case. The result can be higher or lower than the pro forma result, as illustrated in my alternative attrition analysis – the electric attrition result is lower than the pro forma result; the gas attrition result is higher than the pro forma result.

C. Key Differences between PSE's and Staff's Attrition Analyses

Q. In what aspects does your attrition study differ from PSE's?

A. In my attrition analysis, I adopted an attrition base year level that incorporates Staff's disallowances and adjustments in the pro forma case. I utilized different regression functions for gross plant and expense escalation. I also adjusted the historical gross plant data to exclude two additional major investments in recent years. My revised attrition model produces more accurate trending.

1. Staff's Modification to Attrition Base

Q. How did the Company develop its attrition base (i.e., the base level of revenue, expense and rate base)?

A. In the initial filing, PSE witness Free used per-book results of operations as the base level. The attrition base amounts were presented in Free's SEF-9.01E and 9.01G.

Q. Did the Company notify parties of any errors?

A. Yes. The Company informed parties that it discovered errors in its original and supplemental filings, impacting five adjustments to the attrition base:

1. 7.06EP Regulatory Assets and Liabilities;
2. 7.05EP Storm Damage;
3. 6.20E&GP Deferred Gains / Losses;
4. 7.21E&GP Environmental Remediation; and
5. 6.26E&GP Remove Unprotected DFIT.

Correction of the errors decreases the electric revenue requirement deficiency by $9.9 million after attrition for electric and no impact after attrition on gas. (Exh. JL-21).[61]

Shortly after, the Company informed parties that it had discovered additional errors (Exh. JL-22). The AMI and GTZ deferral amounts were inadvertently left out of the attrition base, as well.

Q. Do you agree that the above-mentioned pro forma adjustments should be included in the Company's attrition base, as revised in its response to AWEC Data Request No. 20?

A. Yes, I agree. The five pro forma adjustments should be included in the attrition base. The first five amortizations are calculated amounts that are known for the rate year. The last two additions relate to deferral balances that, if approved, affect both the rate base and the expense in the rate year.

[61] PSE Response to AWEC Data Request No. 20.

Q. What attrition base do you present in this case?

A. I adopted the Company's framework for attrition base. However, I revised the attrition base to incorporate Staff's additional restating and pro forma adjustments. My modification to the attrition base is consistent with Staff's proposed disallowances and other modifications in the pro forma analysis. As both the pro forma and attrition approaches are used to estimate costs in the rate year, items explicitly removed from the pro forma analysis should be removed from the attrition analysis as well. On the electric side, I incorporated the following Staff adjustments to expense and rate base in my attrition base:

- Staff Adjustment 12.01 Remove Smart Burn;
- Staff Adjustment 12.02 Remove Colstrip 2018 outage-related rate base;
- Staff Adjustment 12.03 Remove Green Direct; and
- Staff Adjustment 12.04 Remove Shuffleton.

I also removed the Energy Imbalance Market (EIM) adjustment that the Company included in the pro forma analysis.

On the gas side, I incorporated the following Staff adjustments to expense and rate base in my attrition base:

- Staff Adjustment 12.03 Remove Green Direct; and
- Staff Adjustment 12.05 Remove Tacoma LNG.

I also included adjustments for the AMI and GTZ deferral accounts in attrition base.

Q. How does your attrition base compare to PSE's?

A. I provide a comparison in Table 4 below.

Table 4. Comparison of PSE and Staff's Attrition Base (Before Removing Large Projects)

Electric

	PSE	Staff	Difference
Revenue	$ 1,338,011,579	$ 1,338,173,763	$ 162,184
Expense	$ 971,998,081	$ 964,419,689	$ (7,578,392)
Rate Base	$ 5,204,455,023	$ 5,188,731,886	$ (15,723,137)

Gas

	PSE	Staff	Difference
Revenue	$ 448,086,176	$ 448,115,606	$ 29,430
Expense	$ 344,370,357	$ 341,043,478	$ (3,326,879)
Rate Base	$ 1,961,361,300	$ 1,931,978,462	$ (29,382,838)

2. Staff's Modification to Growth Factor Calculation

Q. How did you modify PSE's growth factor calculations?

A. I replaced PSE witness Amen's exponential growth function with a linear growth function for gross plant to more closely reflect the trend in plant additions over time. I examined the growth trend in each expense category on its own, rather than mixing some together as in Amen's analysis. I also modified historical data to exclude two additional large projects ~~such as AMI, GTZ and CRM~~ to get more accurate growth factors without the influence of those large investments.

a. Staff's Modification to Regression Curves

Q. What growth curves did PSE witness Amen use to develop growth factors?

A. PSE Witness Amen calculated escalation factors based on an exponential function.[62]

$$\ln(y_n/y_0) = \ln(1+r)*n + E$$

Where,

n = independent variable - year

y_0 = dependent variable (plant or O&M) in year zero

y_n = dependent variable (plant or O&M) value in year n

r = growth factor

E = regression error

Q. Do you agree with PSE's approach?

A. No. I disagree with PSE's use of exponential growth function to forecast rate year cost, especially rate base. There is no theory or empirical justification to support an exponential growth pattern in gross utility plant. Exponential growth curves could be applied in some expense categories, but those categories need to be analyzed on a case-by-case basis. Forcing exponential growth curves to the data creates misleading impressions of the expected rate of growth between the test year and the rate year. Whereas the Company suggests rates of growth are accelerating, in most cases rates of growth are fairly stable (i.e., linear).

Q. What growth curve do you use for rate base?

A. I recommend the use of a linear growth curve for rate base projection. The function is as follows:

$$y_n = a + b*n$$

Where,

n = independent variable – year

y_n = dependent variable (plant or O&M) value in year n

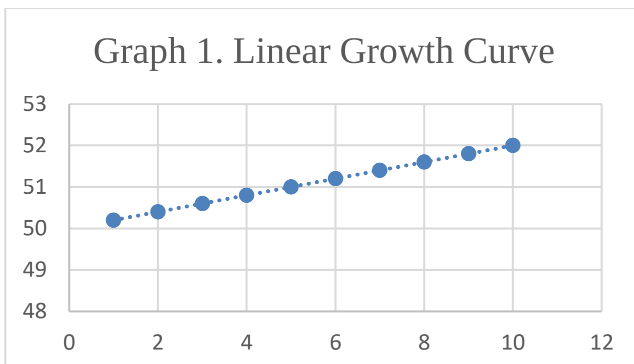
Q. What is the difference between a linear function and an exponential function?

[62] Amen, JRA-1T at 29.

A. Linear growth indicates increases by a constant dollar amount in each period; exponential growth is growth by a constant ratio that compounds over time. Amen argued that if we try to fit a straight line into an exponential curve, the forecast would deviate over the long term.[63] However, the reverse is also true. When PSE fits an exponential curve to a data set with a linear pattern, the forecast will be off. Because the exponential function assumes the growth rate accelerates over time, it tends to overstate the rate of growth into the future.

Q. What does a linear growth curve look like?

A. Here is an illustration:

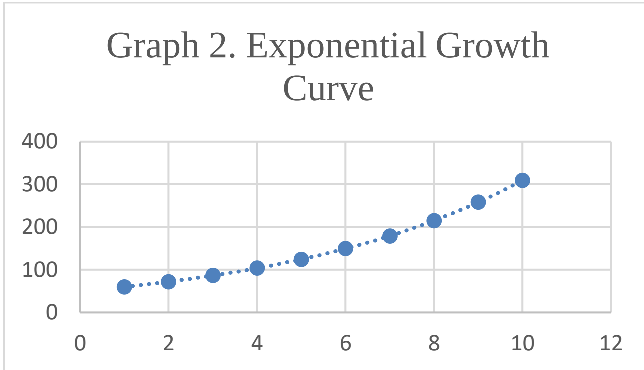


A good example of linear function is the relationship between manufacturing input and output.

[63] Amen, Exh. RJA-1T at 30:1-9.

Q. What does an exponential growth curve look like?

A. Here is an illustration:



Exponential function implies that the underlying forces for growth have a compounding nature. Good examples are compound interest and population growth in some contexts.

Q. Does rate base grow in an exponential fashion or linear fashion?

A. Strictly speaking, neither. I do not believe the Company's decision making on plant additions follows the compound growth rationale. Please see my Exh. JL-23C for PSE's capital expenditure plan for the next five years. The Company's capital investment plan resembles nothing like an upward exponential curve. [redacted].

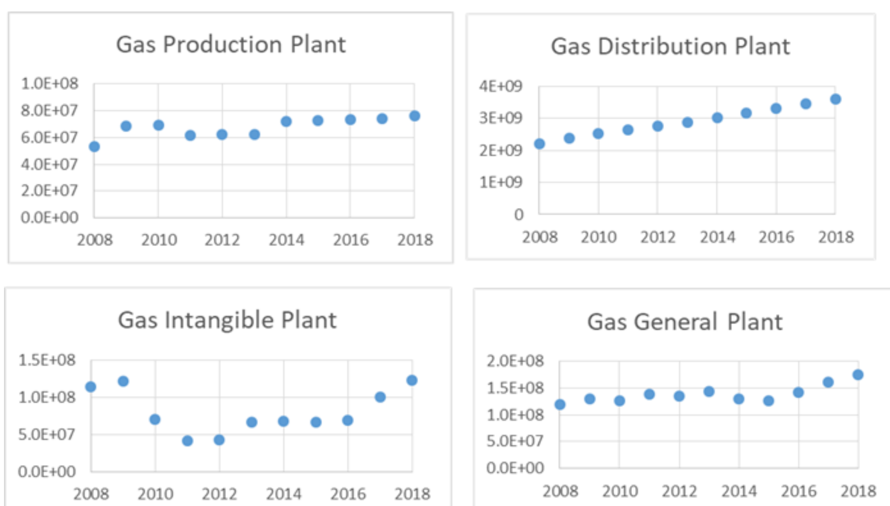
I show the scatterplots of electric gross plant in each function category below. Most of them demonstrate a typical pattern of utility investment with step-wise increases; that is, in one period, a utility will invest heavily in facilities to meet anticipated demand (incline period); in another period, the existing facilities suffice for a few years (plateau period). Without insight into a utility's needs and actual detailed capital budgets, it will be hard to judge whether the rate base in certain categories in the near future will continue to increase, to plateau, or to drop.

Graph 3. PSE's Electric Gross Plant (2008-2018)

Q. Is the gross plant growth pattern very similar for natural gas?

A. Yes. Here is the illustration.

Graph 4. PSE's Gas Gross Plant (2008-2018)



As these charts show, the data do not demonstrate an upward exponential pattern. In most cases, the data grow in a linear fashion, at best, and in an unpredictable pattern at worst.

Q. What happens when you force an exponential growth curve on data points that do not exhibit the pattern?

A. The analysis will produced biased results. Forcing an exponential curve onto underlying data that do not exhibit an exponential pattern of growth will provide misleading expectations with respect to growth into the future. Specifically, forcing an exponential curve onto underlying data that do not exhibit an exponential pattern of growth forces the extrapolation to growth in an accelerated manner into the future, thus overstating the Company's growth in costs.

Q. How do you analyze the above data related to gross plant?

A. I applied a linear growth rate to all gross plant categories. The evidence does not support accelerating growth in plant.

Q. Did you remove Colstrip Units 1 and 2?

A. No. Colstrip Units 1 and 2 will retire at the end of 2019. However, the remaining plant balance will be converted to a regulatory asset per the 2017 GRC settlement agreement. So it will remain as a rate base item. On the expense side, I removed the O&M expense associated with Colstrip Units 1 and 2 because the expense clearly will not occur in the rate year.

Q. Do you agree with the application of exponential growth factors on expenses?

A. It depends. Some expenses escalate over time due to labor cost increases or general inflation. It is possible to model such expense growth either as a linear or exponential function. In the absence of any clear theory for expense escalation, I picked the growth factor from the model with better goodness of fit, as commonly assessed by adjusted R-squared. Where there is goodness of fit, the linear growth factor and exponential growth factor are pretty close. Some expense categories do not show any obvious trend and both models perform poorly. For those categories, I used the compound average growth factor, providing some escalation based on the comparison of expenses in 2008 and 2018.

Q. What other modifications did you make?

A. PSE used growth factors from combined categories for some expenses, such as for combined transmission and distribution expenses as well as combined customer account expense and customer service expense. The combined growth rate is dominated by the growth trend in the larger of the combined categories and skews the results. I provided growth factors from each individual expense category.

PSE applied an O&M growth factor to "other operating expenses." This expense category contains the amortization expense from regulatory deferral accounts that does not exhibit a consistent trend, therefore it should not be trended, so I removed the growth factor. As I mentioned earlier, the amount of deferral expenses from the Company's pro forma adjustments, including AMI and GTZ deferral requests, are included in the attrition base.

b. Staff's Modification to Historical Data

Q. What data did PSE use for its regression analysis?

A. PSE witness Amen used the expense and rate base from 2008-2018 Commission Basis Reports (CBRs).

Q. What is your modification to the historical data?

A. ~~Amen inappropriately included major investments such as AMI, GTZ, CRM, EIM and Tacoma LNG in the CBR historical data. PSE's attrition revenue requirement framework excludes the large investments from the attrition base and adds back the forecast amounts for these projects in the rate year. Therefore, we must exclude the expense and gross plant associated with these projects from the historical data for regression analysis in order to correctly gauge the growth trend for non-major plant. Otherwise the growth factors from the regression models will have an upward bias due to the influence of the large projects in recent years.~~ I excluded two additional major investments: EIM from electric intangible historical data, and~~. I excluded~~ Tacoma LNG from gas distribution historical data.

Q. What other change did you make?

A. I corrected the accumulated deferred income tax for CRM for the rate year. It appeared to be an error. It is now the same amount as shown in Free's adjustment SEF-8.02G.

D. Results from Staff's Attrition Analysis

Q. What is the result of Staff's attrition analysis?

A. The results of my attrition studies indicate attrition revenue requirements of $~~46.1~~47.5 million for electric operations and $~~47.8~~50.5 million for natural gas operations. Relative to Staff's modified historical test year – pro forma approach, my attrition analysis shows an attrition-adjusted revenue *sufficiency* of $~~3.9~~2.5 million for electric operations and an attrition-adjusted revenue deficiency of $~~9.4~~12.1 million for gas operations.

My attrition studies produce revenue deficiencies reasonably close to the revenue deficiencies produced through Staff's modified historical test year approach, indicating that the modified historical test year approach produces revenues sufficient to cover trended growth in costs. I conclude that the evidence does not support a need for an attrition allowance in this case.

My attrition analysis is provided as Exh. JL-19.

Q. What is the main difference between your results and PSE witness Amen's?

A. As shown in JL-20, the main difference is that I provided less escalation to the Company's gross plant, and related to that, less depreciation and amortization expense. In terms of O&M expense, PSE witness Amen and I reached very similar results. Our composite O&M growth factors are within 0.01 percent of each other.

VII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.