Exh. ANH-1Tr
Dockets UE-190529/UG-190530 and
UE-190274/UG-190275 (*consolidated*)
Witness: Aimee N. Higby

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*)**

TESTIMONY OF

Aimee N. Higby

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Pro Forma Policy; Pro Forma Plant Additions; Get to Zero

November 22, 2019

Revised January 31, 2020

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LIST OF EXHIBITS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Aimee N. Higby, 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 aimee.higby@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 Regulation 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 October 2018.

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

A. I earned a Bachelor of Arts degree in History from Columbia University in 2007. I earned a Master of Public Administration degree from Portland State University in 2013. Prior to my employment with the Commission, I spent six years at Bonneville Power Administration (BPA), a federal power marketing agency within the U.S. Department of Energy. While at BPA, I managed multiple projects across the power and transmission business lines, assisted in the development of Power Purchase

Agreements as well as new types of contracts for BPA's Power Services, and analyzed the California Independent System Operator's stakeholder and policy initiatives.

Q. Have you testified previously before the Commission?

A. Yes. I previously testified in Avista Corporation's 2019 general rate case, Dockets UE-190334, UG-190335, and UE-190222, regarding pro forma policy and capital additions.

II. SCOPE AND SUMMARY OF TESTIMONY

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

A. In general, my testimony will provide an overview of the Commission's ratemaking policy and Staff's application of those standards to Puget Sound Energy's (PSE or the Company) proposed pro forma capital additions. Specifically, I address PSE's pro forma adjustments to plant in service:

- 6.24 Get to Zero (GTZ)
- 6.27 Public Improvements
- 6.29 HR Tops
- 7.09 High Molecular Weight Cable
- 7.10 Energy Management System (EMS)

I also address PSE's petition for deferred accounting related to the GTZ initiative through the application of Commission precedent.

Q. Please summarize your recommendations on pro forma capital additions.

A. From a policy perspective, I propose a modification to the materiality threshold for projects placed in service after the test year. When determining whether a project is major, I recommend the Commission consider the depreciable life of the asset in addition to its capital cost. The proposed modification lowers the bar substantially for short-lived assets. Staff witness Chris McGuire discusses the calculation of Staff's proposed materiality threshold.

From a ratemaking perspective, I recommend including pro forma adjustments that would have been excluded under the traditional standard. However, some projects for which PSE requests pro forma treatment still do not meet the lowered threshold and are excluded from Staff's pro forma revenue requirement. I include a pro forma adjustment for EMS and for some, but not all, of PSE's GTZ investments. I exclude pro forma adjustments for Public Improvements, HR Tops, and High Molecular Weight Cable. The tables below show the individual adjustment impacts on net operating income, rate base, and revenue requirement.

Table 1: Impact from UTC Staff Electric Pro Forma Adjustments

Adjustment	Name	Net Operating Income Impact	Rate Base Impact	Revenue Requirement Impact
6.24	Get to Zero	$1,873,878	($8,476,940)	($3,369,363)
6.27	Public Improvements	($296,261)	($12,855,303)	($1,697,987)
6.29	HR Tops	($538,588)	($5,481,050)	($1,272,649)
7.09	High Molecular Weight Cable	($292,768)	($11,899,760)	($1,596,433)
7.1	Energy Management System	-	$263,118	$8,757
	Total	$746,261	($38,449,935)	($7,927,675)

Table 2: Impact from UTC Staff Gas Pro Forma Adjustments

Adjustment	Name	Net Operating Income Impact	Rate Base Impact	Revenue Requirement Impact
6.24	Get to Zero	$957,181	($4,330,040)	($1,714,879)
6.27	Public Improvements	($123,556)	($5,946,648)	($764,743)
6.29	HR Tops	($275,112)	($2,799,732)	($647,730)
	Total	$558,513	($13,076,420)	($3,127,352)

Q. Please summarize your recommendations on PSE's petition for deferred accounting treatment for Get to Zero.

A. I recommend approving in part and denying in part PSE's petition for deferred accounting treatment for past depreciation expense associated with the GTZ initiative. Consistent with Staff's revised materiality threshold for pro forma plant additions, I recommend the Commission allow deferred accounting treatment only for those projects that meet the materiality threshold. I also recommend that the Commission deny PSE's request to include a carrying charge on the GTZ deferral balance, and that it deny PSE's request for open-ended deferred accounting treatment for unidentified future projects placed in service after this rate case. The tables below summarize the impact of Staff's adjustments.

Table 3: GTZ Deferral Electric Operations

Adjustment	Name	Net Operating Income Impact	Rate Base Impact	Revenue Requirement Impact
6.24	Get to Zero	$ 2,572,306	$ (6,041,431)	$ (4,064,184)

Table 4: GTZ Deferral Gas Operations

Adjustment	Name	Net Operating Income Impact	Rate Base Impact	Revenue Requirement Impact
6.24	Get to Zero	$ 1,313,939	$ (3,085,977)	$ (2,068,517)

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

A. Yes. I prepared Exhibits ANH-2 through ANH-5.

- Exhibit ANH-2 is an article which discusses how the trends in digital innovation are changing the operations of utilities and changing customer expectations.
- Exhibit ANH-3 is an article which discusses how the trends in digital innovation are altering the regulatory environment.
- Exhibit ANH-4 is an article which discusses the importance of understanding changing customer expectations and the nexus between customer expectations and utility strategy.
- Exhibit ANH-5 is PSE's response to Staff's data request regarding spending on information technology (IT) assets.

III. COMMISSION RATEMAKING POLICY AND STANDARDS

A. Background

Q. What is the Commission's historical ratemaking practice?

A. The Commission's regulatory framework consists of two components: a modified historical test year, and limited pro forma adjustments.

Q. Please describe the modified historical test year component.

A. The historical test year captures a snapshot of a utility's operations during a defined period of time. The Commission has said:

> The Commission's long-established and well-understood ratemaking practice requires companies filing for revised rates to start with an historical test year. . . . There is a fundamental reason for this starting point in every case: costs, revenues, loads, and all other pertinent factors are known and can be measured with a high degree of certainty because they have, in fact, occurred. The practical value of the historical test year is that the cost, revenue and plant data are available for audit, and the test year captures the complex relationships among the various aspects of utility costs, revenue, load, and other factors over a uniform period of time.[1]

The Commission allows certain restating adjustments to the costs, revenues, and load measured during this test period.[2] These adjustments to the test year capture changes between actual test year results and results under "normal" circumstances.

[1] *Wash. Utils. & Transp. Comm'n. v. Avista Corp*., Dockets UE-160228 & UG-160229, Order 06, 47, ¶ 80 (Dec. 15, 2016).
[2] WAC 480-07-510(3)(c)(i).

Q. Please describe limited pro forma adjustments.

A. Pro forma adjustments allow utilities to reflect post-test year changes to rate base, expenses, or revenues in the revenue requirement calculation. As a general matter, pro forma adjustments are "limited," i.e., they must conform to the Commission's rules on pro forma adjustments.[3] This means that they must be limited to only known and measurable changes not reflected in the test year, and not offset by other factors.

With respect to plant additions, a pro forma adjustment is an adjustment to test year plant balances to account for significant capital projects placed in service after the test year. To the extent that significant post-test year capital additions are not reflected in the revenue requirement calculation, a utility might not have an opportunity to recover its costs and earn a reasonable return on its investments. Pro forma adjustments help to resolve this issue.

However, whether a post-test year project warrants pro forma treatment typically depends on whether the project is determined to be "major." In the next section, I discuss this criterion, as well as other criteria commonly employed by the Commission to determine whether a project warrants pro forma treatment.

B. Commission Standards for Pro Forma Adjustments

Q. What standards have historically been applied to determine whether a post-test year plant addition is appropriate to include as a pro forma adjustment?

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

A. The Commission historically has relied on four basic ratemaking standards in determining whether a post-test year plant addition merits pro forma treatment:

1. Known & Measurable and Offsetting Factors Standard – Are the costs of the project known and measurable? Has the utility identified and incorporated offsetting factors into the revenue requirement calculation?
2. Used and Useful Standard – Is it certain that the plant will be in service and providing benefit to ratepayers during the rate-effective period?
3. Prudence Standard – Did the utility prudently incur costs?
4. Materiality Standard – Does the project meet a reasonable definition of "major?"

I discuss these standards individually below.

1. Known & Measurable and Offsetting Factors Standards

Q. What is the Commission's rule for pro forma adjustments?

A. The Commission's rule on pro forma adjustments states:

> Pro forma adjustments give effect for the test period to all known and measurable changes that are not offset by other factors.[4]

This rule yields the first two standards used by the Commission to determine whether to allow in rates pro forma capital additions: the known and measurable standard and the offsetting factors standard.

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

Q. What is the known and measurable standard?

A. The Commission has stated:

> The known and measurable concept requires that an event that causes a change in revenue, expense or rate base must be *known* to have occurred during or after the historical 12 months of actual results of operations. It must also be demonstrated (*i.e.*, *known*) that the effect of the event will be in place during the 12-month period when rates will likely be in effect.[5] The actual amount of the change must be *measurable.* This means the amount 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. Costs that are documented by actual expenditure, invoice, contract, or other specific obligation usually meet this test. Costs that are the product of forecasts, projections, or budgets generally will not qualify.[6]

Q. What are the practical implications of the known and measurable standard?

A. To be included in rates through a pro forma adjustment, a capital addition must be known to have been placed in service and the final project cost must be measurable. This means that from a practical standpoint, forecasts of costs do not meet the current interpretation of the "known and measurable" standard.[7]

Q. What is the offsetting factors standard?

A. The offsetting factors standard gives effect to the matching principle of ratemaking.[8] It requires consideration of the ripple effects of the investment in question on utility

[5] This is also known as the "rate year."
[6] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Dockets UE-090134 & UG-090135, Order 10, 21 ¶ 45 (Dec. 22, 2009) (Avista GRC 2009).
[7] The Commission recently opened an "Inquiry into the Valuation of Public Service Company Property Used and Useful after Rate Effective Date" in Docket U-190531. Staff filed written comments on August 5, 2019, requesting that the Commission provided guidance on how to apply the "known and measurable" standard going forward.
[8] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-090704 & UG-090705, Order 11, 11, ¶ 25 (Apr. 2, 2010).

operations, such as whether a pro forma investment produces additional revenues or reduces expenses. It requires accounting for the fact that an investment affects more than just rate base and depreciation expense.

Q. What is the importance of offsetting factors in pro forma adjustments?

A. A strict interpretation of the Commission's rule on pro forma adjustments requires that, in order to be included as a pro forma adjustment and included in rates, a capital addition must not be offset by other factors. That is, if the capital addition produces incremental revenues, or if it in some way reduces expenses, it should be disqualified from receiving pro forma treatment. The logic is that increased revenue or decreased expenses associated with the capital additions would offset the need for rate relief associated with the investment. The offsetting factors standard ensures that including pro forma adjustments in rates does not result in the understatement or overstatement of the revenue requirement.

Q. Does the Commission apply a strict interpretation of the offsetting factors standard?

A. Typically not. The Commission recognizes that the annual benefits of a project cannot perfectly offset the annual cost of the investment. Therefore, the Commission typically allows pro forma plant adjustments as long as the offsetting factors that are reasonably expected to exist have been identified, quantified, and included in the revenue requirement calculation.

Q. What are the practical implications of the offsetting factors Standard?

A. With the offsetting factors standard, utilities have the burden of demonstrating *for each and every post-test year plant addition* that either (1) there are no offsetting factors, or (2) offsetting factors have been accurately quantified and incorporated into the revenue requirement calculation.

The practical implication of the offsetting factors standard is that pro forma adjustments are limited to those for which offsetting benefits can be identified and reasonably evaluated. Indiscriminate adjustments to pro forma plant, including aggregate levels of projected plant-in-service, generally fall short of meeting this standard.

Q. How do utilities typically attempt to capture offsetting factors?

A. For pro forma plant, utilities typically include an associated adjustment for operations and maintenance (O&M) offsets. This adjustment accounts for O&M expenses in the test period that will be reduced or eliminated during the rate-effective period as a result of placing specific plant in service after the test year. Each O&M offset is matched to the associated transfer of plant in service; that is, an offset should only be included in the revenue requirement calculation if the associated plant is also included in the calculation.

2. Used and Useful Standard

Q. What is the Commission's used and useful standard?

A. RCW 80.04.250 permits the Commission to value for ratemaking purposes only utility property that is "used and useful for service in this state." The Commission historically has interpreted the used and useful standard to mean that (1) the plant *will be* in service by the rate-effective date,[9] and (2) the plant provides benefits to ratepayers.[10]

Q. What is the importance of the used and useful standard?

A. The standard ensures rates are fair to ratepayers: customers pay through rates for property that is used to provide service.

Q. What is the practical implication of the used and useful standard?

A. If a capital addition is not in service by the time testimony is filed, Staff cannot attest with certainty that the plant will be used and useful by or during the rate effective period. Therefore, in order for Staff to include a project in its revenue requirement calculation, the project should be shown to be in service and providing benefit to ratepayers in advance of the filing date for response testimony.

[9] Avista GRC 2009 at 22, ¶ 48. In 2019, the legislature made clear that the Commission could value property used and useful during the rate effective period. RCW 80.04.250(2).
[10] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.,* Docket UE-050684, Order 04, 21-22, ¶ 50 (Apr. 17, 2006).

3. Prudence Standard

Q. What is the prudence standard?

A. The prudence standard requires utilities to act reasonably in incurring expenses or making investments. [11]

Q. How does the Commission evaluate the prudence of costs claimed in pro forma adjustments?

A. Utilities bear the burden of showing their decisions are prudent.[12] As noted above, the Commission tests decisions for reasonableness. To do so, it examines three factors: "(1) Was the initiation of the project prudent? (2) Was the continued construction of the project prudent? and (3) Were the construction expenses prudently incurred?"[13] The Commission examines these factors throughout the life of a given project.[14]

Q. What are the practical implications of the prudence standard?

A. To recover costs in rates, a utility bears the burden of demonstrating that the investment was necessary, costs were prudently incurred, and that the investment provides benefits to ratepayers. Providing evidence in line with the Commission's

[11] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.,* Docket UE-031725, Order 12, 8, ¶ 19 (Apr. 7, 2004).
[12] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.,* Docket UE-152253, Order 12, 33, ¶ 94 (Sept. 1, 2016).
[13] *Id*. at 34, ¶ 95 (internal citation omitted).
[14] *Id*. at 34, ¶ 95 (internal citation omitted).

parameters is grounded in an *ex post facto* review of what was known at the time of the decision. This is a core component of the regulatory framework and is a cause of regulatory lag, which I discuss later.

4. Materiality Standard

Q. What is the Commission's materiality standard?

A. The Commission has indicated that pro forma adjustments to plant must meet a "reasonable definition of 'major.'"[15]

Q. What is the importance of the materiality standard?

A. Pro forma adjustments to plant are limited to major projects because those are the projects with a material effect on the overall revenue requirement calculation; hence "materiality" standard. This ensures that pro forma adjustments include only projects "relevant to the issue of the financial impact on the Company in the setting of rates."[16]

The Commission's materiality standard also is one of practicality. It is necessary that pro forma plant adjustments be limited in number; otherwise utilities simply cannot meet their burdens of proof for each and every one of their post-test year projects. Further, evaluating pro forma plant additions that are placed into

[15] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.,* Docket UE-140762, Order 08, 73, ¶ 170 (Mar. 25, 2015).
[16] *Wash. Utils. & Transp. Comm'n v. Avista Corp.,* Dockets UE-150204 & UG-150205, Order 05, 17, ¶ 40 (Jan. 6, 2016) (Avista GRC 2015).

service subsequent to the filing of a rate case, without limit, would require a continuous audit during the pendency of the rate proceeding. This would lead to constantly evolving and fluctuating positions for the parties and the Commission. To this point, the Commission has acknowledged there are "limits imposed by the 'used and useful' and 'known and measurable' standards" while continuing to allow "the considerable discretion those standards allow in the context of individual cases."[17]

Q. How has the Commission applied the materiality standard?

A. In past cases, the Commission has relied on utility budget reporting rules to help define a "major" project. WAC 480-140-040 defines major projects in the following manner:

> Major construction projects will be determined for water, gas, and electrical companies, as all projects where the Washington-allocated share of the total project is greater than five-tenths of one percent of the company's latest year-end Washington-allocated net utility plant in service, but does not include any project of less than three million dollars on a total project basis. This determination for companies providing combined industry services will be done on an industry-specific basis.

As the Commission has observed, WAC 480-140-040 is the only directly applicable legal standard for what constitutes a major project.[18] Moreover, the

[17] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.,* Docket UE-130043, Order 05, 79, ¶ 198 (Dec. 4, 2013).
[18] *Wash. Utils. & Transp. Comm'n. v. Pacific Power & Light Co.*, Docket UE-140762, Order 08, 66, ¶ 152 n.222 (Mar. 25, 2015) ("Among the 30 projects included in Pacific Power's filing in this case, only one, the Merwin Project, is indisputably a 'major' plant addition.").

Commission has found the five-tenths of one percent threshold reasonable within the context of a general rate case, observing that:

> [The five-tenths of one percent threshold] has … the advantage of being proportional to the size of the Company's rate base and therefore relevant to the issue of the financial impact on the Company in the setting of rates.[19]

IV. MODIFICATION TO THE MATERIALITY STANDARD

Q. Does Staff recommend modification to the materiality standard?

A. Yes. In an effort to recognize that short-lived assets may have a meaningful financial impact on a utility due to their relatively high depreciation rates, Staff proposes that the materiality standard include consideration of depreciation expense. Doing so will provide a project with a short book life a chance to meet the materiality threshold and qualify for pro forma treatment, even if it does not meet the traditional definition of "major."

Q. How do you recommend modifying the materiality threshold?

A. For assessing the materiality of pro forma plant additions, Staff recommends using a gross cost materiality threshold rather than the traditional 0.5 percent of net plant in service. Staff's gross cost threshold includes depreciation expense as well as return on rate base.

As McGuire states in his testimony, Staff recommends a gross cost materiality threshold of $2,710,000 for electric operations and $1,170,000 for natural

[19] Avista GRC 2015 at 17, ¶ 40.

gas plant. For combined gas and electric plant, Staff recommends a gross cost materiality threshold of $3,890,000. To receive pro forma treatment, a project's annual depreciation expense plus return on gross plant in service should exceed this threshold.

A. Identifying the Problem

Q. Why do you recommend modifying the materiality standard?

A. The Commission has defined major projects as those that are "relevant to the issue of the financial impact on the Company in the setting of rates."[20] However, the traditional materiality threshold limits the definition of "financial impact" to a project's proportional contribution to rate base.

This focus on rate base tends to exclude smaller projects that may have a material financial impact on the company; for example, capital spending on projects with shorter depreciable lives. The financial impact of a project, such as one with a short-depreciable life, is not confined to its proportional contribution to rate base. The financial impact to the Company also includes incremental depreciation expense, which is directly related to the book life of an asset. These investments will likely grow as the industry continues to undergo rapid transformation or as customer expectations evolve.

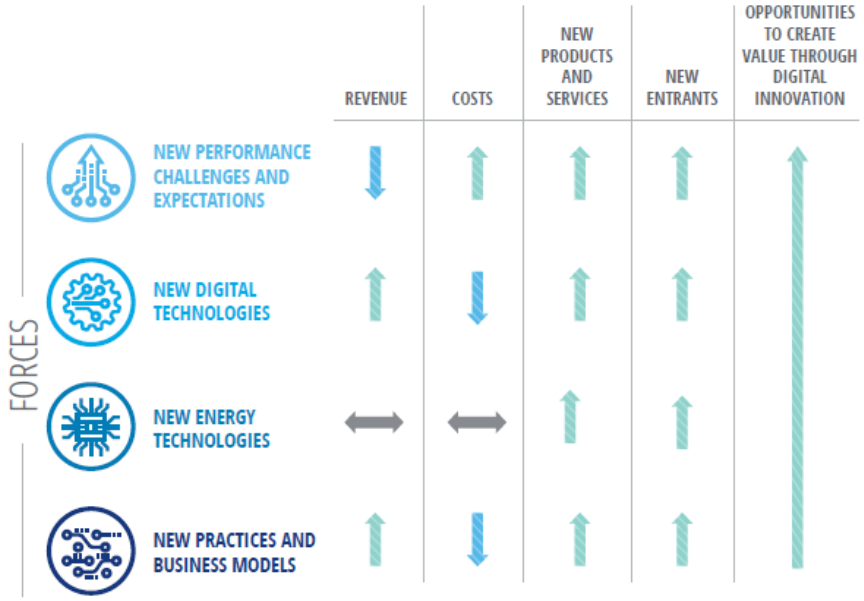
> Overlaying these trends is the advance of digital technologies, sometimes at a breath-taking pace. Technologies such as artificial intelligence, Internet of Things, cloud, and block chain can catalyze new business or operating

[20] *Id*. at 17, ¶ 40.

models, help new entrants disrupt the sector, and enable incumbents to reach new levels of performance.[21]

Innovation, such as IT projects, is a key driver of this trend. Such projects improve operational efficiency and provide new platforms to expand how a utility interacts with its customers. The useful life of these projects is often far shorter than more traditional investments. Figure 1 below demonstrates the high level relationship between changing forces and the general impacts they have on revenues and costs for utilities.

Figure 1: Disruptive Forces Potential Impact on Businesses in the Power Sector[22]



[21] Higby, Exh. ANH-2 at 4.
[22] *Id.* at 5.

Q. What are the consequences of not considering the impact of short-lived assets in the materiality standard?

A. Excluding assets from pro forma plant in service exposes those assets to regulatory lag. If those assets do not have a material financial impact on the utility, the effect of regulatory lag is relatively modest. However, if those assets are short-lived, a utility may be required to absorb a significant portion of the asset's depreciation. This increases the pressure to file serial rate cases to mitigate the effects of regulatory lag. For the regulator, this burdens the process as fatigue builds from the never ending stream of rate case filings.

Q. What is regulatory lag?

A. Regulatory lag is basically a bounded amount of time, generally from 11 to 36 months, that starts when a utility incurs an expense for placing an asset in service and when that utility is allowed additional revenues to recover that cost or investment. Overall, regulatory lag has both advantages and disadvantages.

Q. What are the advantages of regulatory lag?

A. Regulatory lag incents utilities to operate in an efficient manner by controlling costs. The utility generally controls both when to make an investment and when to seek recovery through a rate case. While there are naturally exceptions to this rule, such as replacement for failed assets, it is overall true that the utility has general control of its capital spending.

Q. What are the disadvantages of regulatory lag?

A. Regulatory lag is a direct counter-incentive to investments that produce no revenue or assets with short depreciable lives. Non-revenue generating assets represent immediate expenses that impact the utilities income statement without any corresponding immediate benefit (i.e., revenue).

When an asset has a short depreciable life, a utility is exposed to greater risk of not recovering its costs. For example, an asset with a short depreciable life might provide some revenue, but if those revenues are not sufficient to cover the assets depreciation expense, then the utility "loses" money, all else equal.

Q. Have these disadvantages always been an issue for the utilities?

A. Yes and no. While they have always been present, there were two other factors that reduced the counter-incentive to invest in non-revenue generating or short-lived plant. First, utilities historically have invested in longer-lived plant such as large generation facilities with relatively small depreciation rates. For longer-lived assets, regulatory lag requires the utility to absorb a much smaller fraction of the asset's depreciation. Second, utilities historically have had higher load growth, thus providing revenue growth sufficient to cover the cost of new investments.

Q. Are these disadvantages an issue in today's operating environment?

A. Yes. The shorter an asset's life, the larger proportion of depreciable life exposed to regulatory lag. In contrast, longer lived assets have a relatively minor proportion of

their depreciable lives subjected to regulatory lag; therefore the proportional risk related to cost-recovery is lower.

Additionally, "flat load growth is the new normal."[23] As a result, increases in utility costs have outpaced the natural growth in revenues. Absent revenue increases associated with load growth, utilities must seek revenue increases through general rate cases.

Q. What can a utility, such as PSE, do to reduce regulatory lag?

A. Within the traditional ratemaking process, serial rate cases are one of the only ways to reduce regulatory lag and mitigate the associated effect on recovery of short-lived assets.

B. Proposed Modification to the Materiality Threshold

Q. What is Staff's proposal to change the materiality threshold for pro forma plant additions?

A. Rather than limit materiality to an asset's contribution to rate base, Staff proposes to expand materiality to include the effect of an asset's depreciable life. To do this Staff proposes a gross cost threshold that includes a return on rate base component as well as a depreciation expense component.

[23] Higby, Exh. ANH-4 at 2~~ANH-5 at 4~~ ("flat load growth is the new normal").

Q. Does Staff's proposed modification to the materiality threshold address the problems with regulatory lag created by short-lived assets?

A. Yes. Modifying the materiality threshold allows a broader range of potential projects to meet the Commission standards while honoring the existing standards for pro forma adjustments.

Q. What benefits does Staff's materiality proposal offer?

A. There are several. First, Staff's proposal adheres to a reasonable interpretation of materiality while acknowledging the increasing rate of capital spending on projects with relatively short lives and relatively high depreciation rates.

Second, the inclusion of short-lived projects merely expands the range of *potential* projects that *may* be considered. Staff's modified materiality threshold allows the Commission to assess whether the depreciation expense contributes materially to financial results. This will make meaningful and targeted progress in addressing regulatory lag for utilities investing in short-lived assets, because it acknowledges that smaller but shorter-lived investments may contribute materially to financial results.

Third, this change will relieve some of the pressure on utilities to file serial rate cases, particularly when investments in short-lived plant drive the filing.

Q. Does Staff recommend establishing a specific threshold for determining what qualifies as a short lived asset?

A. No. Staff's proposed threshold includes depreciation expense as well as return on rate base. To the extent that an asset's life becomes a relevant factor, it will be captured in the depreciation component of the modified materiality threshold.

Q. How did Staff calculate the materiality threshold?

A. McGuire provides a detailed explanation of how the materiality threshold was calculated. In summary, Staff relied on both depreciation expense and return on rate base, instead of the existing 0.5 percent of net plant in service. The gross cost threshold allows the Commission to assess whether a capital investment is large enough to be considered "major," as well as whether the depreciation expense contributes materially to financial results.

Q. What gross cost threshold does Staff propose for this case?

A. Staff proposes gross cost thresholds for electric operations, gas operations and electric and gas combined. Staff's threshold is $2,710,000 for electric, $1,170,000 for gas and $3,890,000 for combined.

V. PRO FORMA ADJUSTMENTS

Q. Please summarize the steps taken to review pro forma plant additions.

A. Based on the standards described earlier, Staff applied the modified materiality threshold to PSE's pro forma plant additions to determine what warrants pro forma treatment. Staff does not challenge the prudency of the included pro forma

adjustments. Staff used an attestation period through June 30, 2019, to arrive at the recommendation for pro forma plant additions. There were no associated O&M offsets for the pro forma adjustments that meet Staff's threshold.

Q. What does PSE propose for pro forma adjustments 6.24, 6.27, 6.29, 7.09 and 7.10?

A. Table 5 shows PSE's proposed rate base and net operating income impacts for the adjustments.

Table 5: PSE Proposed Rate Base and Net Operating Income Impacts

Adjustment	Electric Rate Base Impact	Electric Net Operating Income Impact	Gas Rate Base Impact	Gas Net Operating Income Impact
6.24	$ 12,564,559	$ (9,627,594)	$ 6,418,005	$ (4,917,796)
6.27	$ 12,855,303	$ (296,261)	$ 5,946,648	$ (123,556)
6.29	$ 5,481,050	$ (538,588)	$ 2,799,732	$ (275,112)
*7.09	$ 11,899,760	$ (292,768)	-	-
*7.10	$ 4,644,661	$ 2,441,145	-	-
Total	$ 47,445,333	$ (8,314,066)	$ 15,164,385	$ (5,316,464)

*Electric only adjustment

Q. Which of these adjustments meet Staff's proposed materiality threshold?

A. Using the modified materiality threshold the following are included as pro forma adjustments:

- 6.24 GTZ
- 7.10 EMS

The following adjustments did not meet the materiality threshold and were not included as pro forma adjustments:

- 6.27 Public Improvements
- 6.29 HR Tops
- 7.09 High Molecular Weight Cable

VI. ADJUSTMENT 6.24 GET TO ZERO

Q. Why does Staff include GTZ as a pro forma adjustment?

A. Staff recommends the inclusion of one project PSE included under the GTZ umbrella as that project meets Staff's proposed materiality threshold.

Q. What is the GTZ initiative?

A. The GTZ initiative is a series of projects from 2016 to 2021 that are part of PSE's "digital transformation initiative."[24] The initiative is focused on the digital channels customers use to access information about bills, outages, and service requests. GTZ projects are spread across four functional categories: 1) customer interface; 2) billing payment credit and collections; 3) integrated work management; and 4) data management and analytics.

Q. Is the GTZ initiative a single investment or project?

A. No. What PSE calls the GTZ initiative is an amalgamation of numerous discrete projects that are related in the sense that they connect to how customers access information. Some projects were placed in service during the expedited rate filing

[24] *In re Petition of Puget Sound Energy for an Accounting Order*, Dockets UE-190274 and UG-190275, Petition of PSE, 2, ¶ 5 (Apr. 10, 2019).

test year (July 2017 - June 2018), some GTZ projects were placed in service during the test year for this GRC (the calendar year 2018), and some GTZ projects were placed in service during the pro forma period for this GRC (January 2019 - June 2019). Future projects are expected through 2021.

Q. How is GTZ reflected in this rate case?

A. GTZ affects multiple elements of this rate case. Some projects are included in the results of operations while PSE presented others as pro forma adjustments. In addition, PSE filed an accounting petition on April 10, 2019, to defer depreciation expense associated for qualifying projects, which I discuss separately in Section VII.

Q. What does Staff recommend regarding the pro forma adjustment for the GTZ Initiative?

A. Staff recommends including some GTZ investment as a pro forma adjustment to plant, but only for the one project that meet the Commission's policy standards for pro forma adjustments, including the materiality standard. GTZ is a pro forma adjustment for both electric and gas operations.

Specifically, Staff recommends the inclusion of one project in pro forma plant, which decreases PSE's requested revenue requirement $3,369,363 for electric operations and $1,714,879 for gas operations.

VII. DEFERRED ACCOUNTING

Q. Please describe the Company's GTZ deferred accounting petition.

A. PSE requests to: 1) defer depreciation expenses for Get to Zero (GTZ) investments with a book life of 10 years or less; 2) allow a monthly carrying charge equal to the current rate of return; and 3) approve continued use of deferred accounting treatment for future qualifying GTZ investments placed in service after rates are established in this GRC.

Q. Why is PSE requesting deferred accounting?

A. PSE provides three conditions that it says justify this accounting petition: 1) IT investments are required to deliver services to ratepayers; 2) IT capital spending has increased significantly relative to total capital spending; and 3) the impact of regulatory lag for short-lived assets.

Q. Please summarize your recommendations.

A. Staff recommends approving, in part, the accounting petition. Staff recommends that the Commission allow deferred depreciation for the projects that meet Staff's proposed materiality threshold, which would total $16,687,554. Staff recommends that the Commission deny the request to include a carrying charge on the deferral balance. Staff recommends that the Commission deny the request for open-ended deferred accounting treatment for unidentified future projects.

A. Background

Q. What is deferred accounting?

A. In layperson's terms, deferred accounting treats an expense from one period as though it was incurred in a future rate period.[25] For example, if a utility incurs a large expense to recover from a catastrophic winter storm, the utility may request to "defer" those expenses so that it may recover them later (i.e., recover them in rates). Absent deferral, the utility recognizes the costs in the period in which it incurred them, and it would not recover them.

If the Commission authorizes deferred accounting treatment, the utility records the expense as a regulatory asset until a rate case, at which point the utility treats the cost as an expense in the rate year and can therefore include it in rates.

Q. When is deferred accounting treatment used?

A. Typically, the Commission authorizes deferred accounting treatment to help mitigate the financial impact to a utility of large, unexpected costs that could not have been considered when setting rates. Thus, deferred accounting typically is reserved for extraordinary circumstances.

[25] Deferred accounting can also be used for revenues.

Q. What constitutes extraordinary circumstances?

A. The Commission has generally concluded that extraordinary or "exceptional" circumstances are those that 1) are beyond the regulated company's control[26]; and 2) generate costs that have a material impact on the utility's financial results.[27] Examples of circumstances that have been deemed extraordinary in the past include: costs related to declining hydroelectric generation, power costs from the 2001 energy crisis, and BPA's residential exchange program. The Commission's authorization of deferred accounting treatment represents tacit acknowledgment that absent a deferral, authorized rates are insufficient. In general, Staff believes deferred accounting should be used only for extraordinary circumstances, outside of the utility's ability to control.

B. Evaluation of PSE's Petition

Q. How does Staff evaluate PSE's accounting petition?

A. First, I evaluate PSE's operating environment to judge whether there are extraordinary circumstances justifying the use of an accounting petition. Second, I evaluate the amounts included in the accounting petition to see if they are material enough to warrant deferred accounting treatment.

[26] Pacific Power GRC 2014, Order 8, 107, ¶ 251 ("We emphasize, then, that the treatment we allow is in this instance is exceptional and turns on the unusual nature of the project involved.").
[27] *Wash. Utils. & Transp. Comm'n. v. Nw. Nat. Gas Co.*, Docket UG-080519, Order 01, 3, ¶ 7 (May 2, 2008).

1. The Utility Landscape Constitutes Extraordinary Circumstances

Q. How does the Commission determine extraordinary circumstances?

A. It is unclear. Staff does not know where the Commission would draw the line between ordinary and extraordinary circumstances because of the wide range of circumstances for which the Commission has authorized deferred accounting treatment. Staff recommends the Commission offer further policy guidance on this matter, either through a standalone policy docket or as part of the Commission's existing Inquiry into the Adequacy of the Current Regulatory Framework (AFOR Inquiry).[28]

Q. Are there extraordinary circumstances supporting the Company's petition?

A. Yes, Staff believes there are. While PSE's current situation is not as clearly defined as the 2001 energy crisis or costs related to mandated licensing, Staff agrees there are unique conditions that are outside of the Company's control.

> The sector is being reshaped by forces that have been evolving and converging for more than a decade. From rising costs and changing load patterns, to newly viable technologies, regulatory change and the growing call to decarbonize, disruptive forces are transforming the industry, driving it toward a new and different future.[29]

[28] *See generally Inquiry into the Adequacy of the Current Regulatory Framework Employed by the Commission in Addressing Developing Industry Trends, New Technologies, and Public Policy Affecting the Utility Sector (AFOR)*, Docket U-180907 ("*AFOR*"). The AFOR docket is an inquiry examining if the traditional regulatory framework is adequate for the evolving utility landscape. The Commission generally has regulated the provision of utility service through traditional rate-base, rate-of-return regulation; however transformational change brought on by new technologies, rapidly changing costs, and emerging opportunities for customers and utilities may produce conditions in which traditional regulation is not the most efficient and effective means of achieving the Commission's public interest objectives.

[29] Higby, Exh. ANH-2 at 4.

PSE, and the utility industry as a whole, is faced with enormous change spurred by technological innovation and increasing customer engagement. This disruption exists alongside a regulatory framework that is out of step with 21st century technology. Therefore, investment spending creates an environment in which utilities seek the use of extraordinary tools.

> The assumption that regulations can be crafted slowly and deliberately, and then remain in place, unchanged for long periods of time, has been upended in today's environment. As new business models and services emerge…government agencies are challenged with creating or modifying regulations, enforcing them, and communicating them to the public at previously undreamed-of pace. And they must do with while working within legacy frameworks *and* attempting to foster innovation.[30]

Q. How does the changing utility landscape present extraordinary circumstances?

A. The broader industry landscape has been swept up in a sea of technological innovation, which has disrupted the traditional business model. Utilities are forced to accommodate and understand these changes, learn how they affect day-to-day operations, identify how to incorporate them into planning, and ascertain what changes this means for how utilities interact with the current regulatory framework.

> We have a legal, regulatory framework built on the basis of mail, paper, words, versus a new world order which is digital, 24/7, and built on bits and bytes. Somehow we need to square these two worlds.[31]

[30] Higby, Exh. ANH-3 at 4.
[31] *Id*. at 8.

Similar to how mobile technology disrupted the telecom industry, the utility industry now faces grid digitization. This is discussed in some detail by Staff Witness Jason Ball.[32]

Q. How do changing customer expectations affect the utility landscape?

A. Modern, near instantaneous access to data means that customers have the option, and expectation, of real-time, accurate information. This can be related to outages, billing, service requests, or usage. Utilities must update their systems, processes, and software to provide customers the options of how to interact with them. "Customer preferences are growing in diversity and complexity. Energy services technology and alternatives to utility service are dramatically more accessible,"[33] which has forced utilities to rethink the services and options they offer customers as well as how they communicate with one another. This goes beyond how electricity is produced – customers want to choose *how* they communicate with their utility.

Q. Do others have concerns about the evolving utility landscape?

A. Yes. The Commission began investigating this very issue when it opened the AFOR Inquiry. When asked "How are developing industry trends, new technologies, and public policy in the utility sectors affecting the effectiveness of traditional rate-base, rate-of-return regulation?" Climate Solutions responded:

[32] Ball, Exh. JLB-1T, at 41. Ball discusses how customer expectations changed with the advent of new technology and software. He extrapolates that the utility industry is undergoing a similar transformation.
[33] Higby, Exh. ANH-4 ~~ANH 3~~ at 2.

> In the current regulatory structure, utilities are incentivized to make large capital investments in order to keep the utility financially healthy. This does not always align with public interest.[34]

Pacific Power and Light Company stated:

> The current regulatory system has supported the goals of equity, affordability, and universal access, while ensuring safety and reliability. The task that now faces this industry is to continue to support these goals while promoting innovation, increased alignment of customer and utility incentives, and support for state policies.[35]

Alliance of Western Energy Consumers noted:

> In essence, traditional utility regulation imposes the full risk of uncertain future events on customers. Alternative regulation should be designed to address these systematic deficiencies in a manner that inures to the benefit of customers and voids unfair treatment for the utilities.[36]

Avista Corporation declared:

> Each of the pressures identified [changes in business conditions, customer requests, public policies related to energy generation and distribution, customer privacy and cybersecurity] put operating and financial constraints on the utility, which traditional rate-making treatment with its built-in regulatory lag, cannot overcome. The effectiveness of traditional regulation is therefore at question, increasing regulatory risk, increasing the costs of maintaining utility systems, and ultimately increasing costs to serve customers. Given the developing industry trends, current financial incentives of the utility may no longer be aligned with customer needs, nor with the Commission or State policy goals.[37]

Q. How has the Commission begun responding to these industry changes?

A. There is recognition within the industry and by the Commission that current framework has not adapted to accommodate the changing milieu. The Commission implicitly acknowledged the transformation the industry is undertaking through the

[34] *AFOR*, Docket U-180907, Comments of Climate Solutions, 2 (Jan. 17, 2019).
[35] *AFOR*, Docket U-180907, Comments of Pacific Power and Light Company, 3 (Jan. 17, 2019).
[36] *AFOR*, Docket U-180907, Comments of Alliance of Western Energy Consumers, 4-5 (Jan. 17, 2019).
[37] AFOR, Docket U-180907, Appendix A of Avista Corporation, 1 (Jan. 17, 2019).

AFOR Inquiry. Additionally, the Commission utilizes increasingly complex policy solutions to address the symptoms of the evolving utility landscape, such as large investments in short-lived IT projects.

Q. What are the increasingly complex policy solutions that the Commission uses?

A. Over the past few years, there has been a noticeable uptick in the frequency of rate cases, multiple cases featuring attrition, proposals for new decoupling mechanisms, and requests for expedited rate filings. So far then, utilities and the Commission are relying on traditional mechanisms to address new challenges. This may indicate a systemic problem in the current regulatory framework, in so far as traditional mechanisms were designed to deal with specific challenges. Rather than recycling extraordinary tools that are highly complex and require significant analytical oversight to implement, utilities and the Commission should examine new forms of rate making designed for the modern era. For instance, it may be useful to consider the use of performance incentive mechanism's that are attached to specific operational targets for IT infrastructure spending.

Q. In summary, what extraordinary circumstances justify the Company's accounting petition?

A. There are multiple intertwined components that create extraordinary circumstances for this accounting petition. The individual components begin with the accepting the premise that the utility landscape is undergoing immense evolution. This evolution is occurring in conjunction with vastly changing customer expectations. This creates a

gap with a regulatory framework that was purposely developed as a slow, deliberative process, but is now at odds with the break-neck speed at which the industry is evolving. To combat the issue of regulatory lag, the Commission is relying on increasingly complex policy tools to combat the regulatory issues the new environment has created while simultaneously investigating the issues that utilities and stakeholders face in this brave new world.

2. The Accounting Petition will have a Material Impact

Q. What constitutes a material effect on a utility's financial results?

A. With respect to accounting petitions and materiality, thus far the Commission has offered only generic guidance:

> In prior decisions concerning accounting petitions, the Commission has determined that deferred amounts must be of a magnitude such that recording costs…has a material impact on company earnings.[38]

The Commission has yet to further clarify what constitutes a material impact. Staff encourages the Commission to offer more explicit guidance on how to quantify a material impact. Until such direction is offered, utilities will create their own definition in each accounting petition filed which may result in inconsistent interpretations of materiality.

[38] *Wash. Utils. & Transp. Comm'n. v. Nw Nat. Gas Co.*, Docket UG-080519, Order 01, 3, ¶ 7 (May 2, 2008).

Q. Does Staff have a recommendation on how to define material impact?

A. Yes. When evaluating accounting petitions related to utility plant additions, Staff recommends applying the same materiality threshold that was used for pro forma plant. This is primarily because PSE's petition for deferred accounting treatment requests deferral of past depreciation expense for *utility plant.* This is an unusual request as utilities generally have some control over the timing of their investment spending, calling into question whether utility plant should be considered an extraordinary event. Setting aside this issue, it is important to note that Staff's proposed materiality threshold is relevant only for costs associated with pro forma *plant additions*. If the Commission determines utility investments in plant are not extraordinary events outside of the control of the Company, then the materiality threshold becomes irrelevant to accounting petitions.

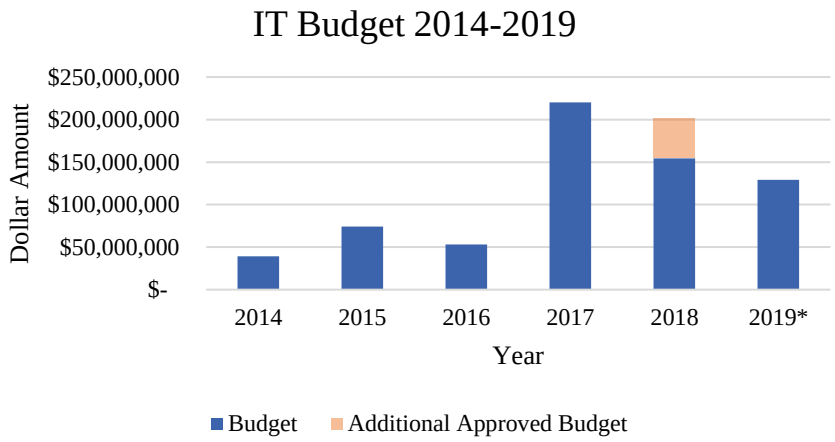
The materiality threshold should be applied when considering whether costs associated with an individual investment contribute materially to the Company's financial results. For instance, Staff is not convinced, nor should the Commission be, that an investment of $823,000 that has a book life of 10 years and an annual depreciation expense of $82,000 is a material expense worthy of extraordinary regulatory treatment.

Q. Does GTZ represent a material impact worthy of deferral accounting?

A. Yes. As Figure 2 depicts, overall IT spending has substantially increased over the past five years. Staff applied the modified materiality threshold to the projects placed

in service across 14 dates. Using the materiality threshold, projects placed in service on three of those 14 dates qualify as material.

Figure 2: PSE IT Budget: 2014-2019[39]



*Unknown if any additional budget was approved for 2019

Q. What is the effect of applying a materiality threshold to PSE's petition?

A. PSE asks for $30,551,970 to be deferred as depreciation expense in the accounting petition. When Staff's proposed materiality threshold is applied to the GTZ accounting petition, it drops the deferred depreciation amount to $16,687,554.

C. Staff Recommendation on the Accounting Petition

Q. Please Summarize Staff's position on the accounting petition

A. Staff recommends approving, in part, the accounting petition. First, the Commission should allow deferred depreciation for the projects that meet Staff's proposed

[39] Higby, Exh. ANH-5 at 2-3.

materiality threshold, which total $16,687,554. Second, the Commission should deny the request to include a carrying charge on the deferral balance. Third, the Commission should also deny the request for deferred accounting treatment for future projects placed in service after this rate case.

Q. Why should a carrying charge not be allowed to accrue on the deferral balance?

A. Authorization of the accounting petition itself represents an extraordinary regulatory action, providing the Company with special treatment of depreciation expense, even though those expenses occurred during a period in which the Commission has already determined rates to be sufficient.

Q. Why does Staff advise against including future investments automatically in this deferred accounting treatment?

A. PSE is requesting deferred accounting treatment of hypothetical expenses for projects that have not been identified. It is not possible to assess whether circumstances are extraordinary if the circumstances do not yet exist. Further it is not possible to assess materiality because the rates in effect for that period have not yet been authorized.

Moreover, if the Commission approves the deferral for unspecified future investments, it is acquiescing to the Company's assertion that rate year revenues will be insufficient the moment they are authorized. The Commission should reject this notion outright.

Q. Does this conclude your testimony?

A. Yes.