BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2152

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Detailed Depreciation Study of Electric Utility Properties.	ERRATA TO MOTION TO ADMIT OF THE STIPULATING PARTIES

Staff of the Oregon Public Utility Commission, Portland General Electric and the Citizens' Utility Board (collectively, the Stipulating Parties) identified that Stipulating Parties/200, filed on September 27, 2021, was not accompanied by a motion to admit into the record of this proceeding. To correct this error, the Stipulating Parties submit this errata and move for admission into the record of this proceeding the following exhibits submitted on behalf of the Stipulating Parties.

Exhibit	Description
Stipulating Parties/200	Stipulating Parties Reply Testimony and Exhibits
Stipulating Parties/201	Colstrip Enabling Study
Stipulating Parties/202	FERC Uniform System of Accounts Prescribed for Public Utilities, Section 22, Depreciation Accounting
Stipulating Parties/203	Portland General Electric Wind Retirements in 2020 and 2021 for FERC Account 344.01

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/ / /

Department of Justice
1162 Court Street NE
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DATED this 19th day of October 2021.

Respectfully submitted,

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BEFORE THE PUBLIC UTILITY COMMISSION OF THE STATE OF OREGON

UM 2152

Stipulating Parties Testimony in Response to AWEC's Objection to the Stipulation

Reply Testimony of

Ming Peng, OPUC

Will Gehrke, CUB

John Spanos, On behalf of PGE

September 29, 2021

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I. INTRODUCTION AND PURPOSE

Q. Please state your names and positions.

A. My name is Ming Peng. I am a Senior Econometrician for the Public Utility Commission of Oregon (Commission). My business address is 201 High St. SE, Suite 100, Salem, Oregon, 97301.

My name is William Gehrke. I am an economist employed by the Citizens' Utility Board (CUB).

My name is John J. Spanos. I am President at Gannett Fleming Valuation and Rate Consultants, LLC. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania 17011. I represent Portland General Electric Company (PGE) in this docket.

Collectively we represent the Stipulating Parties in Docket No. UM 2152.

Our qualification statements are found in Stipulating Parties Exhibits 105, 106 and 107.

Q. What is the purpose of your testimony?

A. Our testimony responds to the testimony of Alliance of Western Energy Consumers ("AWEC") witness Lance Kaufman on issues related to depreciation.

Q. Please summarize your testimony.

A. On July 29, 2021, PGE filed a Stipulation resolving issues in this case. All parties agreed to the Stipulation except AWEC. AWEC witness Lance Kaufman provides testimony proposing a variety of adjustments to the depreciation rates and parameters agreed to in the Stipulation. The most notable proposal is to significantly reduce depreciation expense by over $50 million per year through a short-term reduction in depreciation expense based on a calculated theoretical reserve imbalance or what Mr. Kaufman refers to as “excess reserves”. The result of this proposal is that once this short-term reduction concludes, customers will experience a significant increase in depreciation expense of at least $50 million. This increase is due to both the expiration of Mr. Kaufman’s proposal and higher depreciation rates that result from a lower accumulated depreciation balance. Customers will also have to pay for a much higher rate base.

In addition to his proposal related to the amortization of the reserve, Mr. Kaufman has proposed adjustments to interim survivor curves for various generation accounts, survivor curve estimates for two transmission accounts, net salvage estimates for two accounts and an increase in the life span for one hydro facility. We will address each of these proposed adjustments in our testimony. However, it is important to recognize that the parties to the Stipulation have all agreed to the service lives and net salvage included in the Stipulation. Mr. Kaufman’s recommendations are largely unreasonable, based on flawed assumptions, and incomplete, as Mr. Kaufman did not calculate or propose any depreciation rates to determine the overall impact on PGE’s depreciation expense. Consequently, Mr. Kaufman has not provided adequate reason and supporting analysis to deviate from the estimates agreed to by the parties to the Stipulation.

II. THEORETICAL RESERVE IMBALANCE

Q. What is a theoretical reserve imbalance?

A. A theoretical reserve imbalance ("TRI" or "imbalance") is calculated as the difference between a company's book accumulated depreciation, or book reserve, and the calculated accrued depreciation, or theoretical reserve. We should note that in some proceedings in this and other jurisdictions, different terms have been used for the theoretical reserve imbalance, including "theoretical reserve variance," “excess reserve,” "reserve surplus" or "reserve deficit" and "theoretical excess depreciation reserve." For this testimony we will use the term "theoretical reserve imbalance," which is consistent with the terminology used in the National Association of Regulatory Utility Commissioners' ("NARUC") publication *Public Utility Depreciation Practices*. Terms such as “excess reserve,” and “reserve surplus” can be misleading, since they imply that the theoretical reserve is a more precise figure than it is. These terms also suggest that accumulated depreciation represents a pool of money or funds that can be used for various financial objectives, which is not the case.

Q. What is the book reserve?

A. The book reserve, also referred to as the “book accumulated depreciation” or the “accumulated provision for depreciation,” is a running total of historical depreciation activity. It is equal to the historical depreciation accruals, less retirements and cost of removal, plus historical gross salvage. The book reserve also represents a reduction to the original cost of plant when calculating rate base.

Q. What is the theoretical reserve?

A. The theoretical reserve is an estimate of the accumulated depreciation based on the current plant balances and depreciation parameters (service life and net salvage estimates) at a specific point in time. It is equal to the portion of the depreciable cost of plant that will not be allocated to expense through future whole life depreciation accruals based on the current forecasts of service life and net salvage. The theoretical reserve is also referred to as the "Calculated Accrued Depreciation" or "CAD."

Q. How is the theoretical reserve calculated?

A. Using the average service life procedure employed for this study, the theoretical reserve is calculated for each vintage in each depreciable group using the following formula:

Theoretical Reserve = (Original Cost - Net Salvage) x (1-Remaining Life/Average Service Life)

The remaining life and average service life are determined for each vintage (year of installation) based on the survivor curve estimate (life and dispersion pattern). The theoretical reserve for an account is equal to the sum of the theoretical reserve amounts for each vintage.

Q. Why is it called theoretical?

A. The reserve is called theoretical because it is not based upon actual recorded depreciation resulting from the application of depreciation rates used by the Company and approved by the Commission. Instead, it is an estimate based on the formula described previously.

Q. Why does one calculate a theoretical reserve?

A. A theoretical reserve is calculated as an analytical tool or benchmark to identify how current estimates compare to the provisions using previous estimates in calculating annual depreciation. It can also be used as a basis to allocate the book reserve to accounts, subaccounts or vintages of plant. A theoretical reserve calculation provides a snapshot of the reserve, valid only at the time it is calculated, since any changes in the proposed parameters or plant and reserve activity will change the theoretical reserve.

Q. Mr. Kaufman argues that the difference in the book and theoretical reserve represents an "excess" in the accumulated provision for depreciation. Is that accurate?

A. No. While there is a difference between book accumulated depreciation and the theoretical depreciation reserve, this amount is not an "excess." It is simply a theoretical calculation of the difference between the actual accumulated depreciation, based on the Company's historical experience and Commission-approved depreciation rates, and a theoretical amount based solely on the proposed depreciation parameters. Depreciation is a prospective calculation, and thus changes as life and net salvage parameters change in future studies. As the Company moves through time with varying experience, this difference can change positively or negatively.

There are also reasons that we might expect the theoretical reserve imbalance to decrease in the future. The electric industry in Oregon and neighboring states is going through a significant transition from fossil fuels to other energy sources. It is very possible that, as the electric system is updated to incorporate these fuel sources, assets will be replaced at a more rapid pace than has occurred historically. Further, PGE has, in recent years, made significant investments to their Transmission and Distribution systems, and its service territory continues to experience the effects of climate change and severe weather (wildfires in 2020 and a major ice storm in 2021) which result in unanticipated damages to those systems.

Given these circumstances, the theoretical reserve imbalance will decrease and could even become a negative amount. If Mr. Kaufman's proposal to effectively reduce this amount to zero over the next ten years were adopted, it is very likely that the theoretical reserve imbalance would be negative in future depreciation studies.

Q. Is the theoretical reserve imbalance harmful to current customers?

A. No. In fact, current customers benefit from the existence of a theoretical reserve imbalance in two ways. The first is that depreciation based on the remaining life technique is lower than it otherwise would be. The second is that, because the book reserve is a reduction to the original cost of plant, rate base is lower and customers pay a lower return on rate base. Current customers are not harmed from a theoretical reserve imbalance that developed over many years.

Q. What is Mr. Kaufman's proposal in this case related to the theoretical reserve imbalance?

A. Mr. Kaufman is proposing (1) to transfer "excess" reserve from accounts in various functions to the steam production accounts to equal the future accruals expected for Colstrip and (2) to amortize the remaining portion of the theoretical reserve imbalance over a ten-year period.

Q. Is Mr. Kaufman's proposal a common practice in the industry?

A. No. Most utilities, Commissions and depreciation texts agree that theoretical reserve differences frequently exist and are best resolved using the remaining life technique. The remaining life technique is the most widely accepted approach and should be used unless unique and significant circumstances otherwise warrant deviation from this practice. While Mr. Kaufman discusses at length the size of the theoretical reserve imbalance, he does not provide any unique circumstances that would require addressing the reserve imbalance more quickly than occurs from using the remaining life technique. The theoretical reserve imbalance is developed over many years and is based on estimates of the future. It, therefore, should not be resolved in a short period of time, as Mr. Kaufman proposes. It is more appropriate to allocate costs through depreciation over the remaining time the Company's assets will be in service using the remaining life technique. Mr. Kaufman's amortization approach is a short-term subsidy for current customers that will result in increased costs for future customers.

Further, his proposal to transfer reserve across functions is not appropriate. While he minimizes such issues in his testimony, there are cost allocation issues and potential jurisdictional issues with transferring reserves from other functions such as transmission and distribution to generation. For this reason, the Federal Energy Regulatory Commission ("FERC") has not typically allowed transfers of reserves across functions.

Q. Has the Commission accepted the use of the remaining life technique for PGE in the past?

A. Yes. The Company has used the remaining life technique for developing depreciation rates for many years. The remaining life technique has been accepted by the Commission for other utility companies in Oregon as well. To our knowledge, Mr. Kaufman's approach has not been approved in Oregon.

Q. Referring to authoritative sources, what does the National Association of Regulatory Utility Commissioners (NARUC) say regarding this issue?

A. NARUC makes several comments regarding theoretical reserve imbalances in its publication *Public Utility Depreciation Practices*. On page 189, NARUC states:

> When a depreciation reserve imbalance exists, one should investigate why past depreciation rates, average service lives, salvage, or cost of

> removal amounts differ from the current estimates. Care should be taken to analyze these effects before correcting for the reserve imbalances. Instances occur where subsequent experience shows the original estimates no longer to be appropriate. It should be noted that only after plant has lived its entire useful life will the true depreciation parameters become known.[1]

Q. Does NARUC provide additional guidance addressing the remaining life technique?

A. Yes. NARUC also notes that:

> The desirability of using the remaining life technique is that any necessary adjustments of depreciation reserves, because of changes to the estimates of life and net salvage, are accrued automatically over the remaining life of the property. Once commenced, adjustments to the depreciation reserve, outside of those inherent in the remaining life rate would require regulatory approval.[2]

Combined with the NARUC passage cited earlier urging caution, NARUC's recommendation is that for companies like PGE that use the remaining life technique, any accelerated amortization, such as proposed by Mr. Kaufman, must be based on unique circumstances that justify specific Commission approval. Despite Mr. Kaufman's claims, such circumstances do not exist for PGE, and the size of the reserve imbalance alone does not justify such treatment.

[1] *Public Utility Depreciation Practices*, NARUC, 1996, pp. 189.
[2] NARUC, p. 65.

We note that Mr. Kaufman cites this same passage in his testimony. However, he completely misinterprets the meaning of this passage, claiming that NARUC "explicitly calls out the necessity for commissions to approve depreciation reserve adjustments for utilities that rely on the Remaining Life Technique."[3] This is, in fact, the exact opposite of what NARUC says, and in no way does NARUC indicate a "necessity" for reserve adjustments when the remaining life technique is used. When one reads the full passage, it is clear that NARUC means that the reserve adjustments are not necessary if the remaining life technique is used because the remaining life automatically corrects any reserve imbalances. Any explicit adjustments would be relatively rare and, as a result, would "*require* regulatory approval" (emphasis added). That Mr. Kaufman's interpretation is incorrect is also evidenced by the fact that the vast majority of depreciation studies using the remaining life technique do not incorporate a reserve adjustment similar to what Mr. Kaufman proposes.

Q. Mr. Kaufman cites a handful of cases in which amortizations of theoretical reserve imbalances were adopted. Are these common?

A. No. Additionally, for some of the cases cited by Mr. Kaufman, subsequent depreciation studies resulted in negative theoretical reserve imbalances. That is, subsequent experience indicated that such adjustments were incorrect. For example, he cites an

[3] Kaufman at 23.

amortization of the reserve imbalance for PacifiCorp's Hunter Plant approved by the Idaho Commission. However, in PacifiCorp's more recent depreciation study this plant had a negative reserve imbalance. This illustrates the concept that reserve imbalances change over time and provides a reason why dramatic actions, such as proposed by Mr. Kaufman, are not sound policy. Additionally, PacifiCorp also files studies in Oregon and the same treatment was not adopted here as was in Idaho.

We note that Mr. Kaufman has only cited a handful of cases over the course of more than a decade in which a similar proposal to his was adopted. One case is from New York, which does not use the remaining life technique, and so is not relevant. That he has cited so few cases illustrates that such approaches are, in fact, quite rare. In the majority of depreciation studies across the country, the remaining life technique is used, and an additional amortization is unnecessary.

Notably, Mr. Kaufman has not cited any cases from Oregon. He also does not note that the FERC has rejected his approach and found that it is not consistent with the Uniform System of Accounts (USofA).

Q. Please discuss the case in which the FERC rejected an amortization of the theoretical reserve imbalance.

A. Progress Energy Florida (now Duke Energy Florida) filed its depreciation study before the FERC in Docket No. ER11-2584-000. FERC stated in its Order:

> In this regard we note that this Commission has addressed any alleged excess or deficiency in depreciation reserves through adjustment of depreciation rates that eliminate such excess or deficiency over the remaining life of a utility's plant, rather than any shorter period.[4]

In other words, an accelerated amortization of the reserve was not accepted. Additionally, FERC further stated in Docket No. ER11-3584-000 that:

> In Order No. 618 and in the February 28 Order, the Commission stated that the cost of property used in utility operations should be allocated in a "systematic and rational manner" to periods during which the property is used in utility operations, i.e., over the property's remaining estimated useful service life. For this reason, changes in asset depreciation estimates, including cost of removal, should be made prospectively over the asset's remaining life. Florida Power proposes to adjust its depreciation reserves by $65,840,613 in 2010 and intends to adjust its depreciation reserves by varying amounts in 2011 through 2013 rather than allocating the excess depreciation reserves over the remaining service lives of the related utility plant. While these adjustments may be acceptable for retail ratemaking purposes, they do not conform to our requirements for allocating the costs of utility plant over their service lives. Accordingly, we will direct Florida Power to reinstate all such adjustments to its depreciation reserves (Account 108). Florida Power must also re-file its 2010 FERC Form No. 1 to reflect the restatement of its depreciation reserves.[5]

Q. Based on the FERC's decision cited above, does the FERC consider Mr. Kaufman's proposal consistent with the USofA?

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[4] Order in FERC Docket No. ER11-2584-000, p. 10, footnote 44.
[5] Order in FERC Docket No. ER11-3584-000, paragraph 9. (Emphasis added).

A. No. The cited passages above make clear the FERC's opinion that the USofA requires that any reserve imbalances be allocated over the remaining lives of a Company's assets (e.g., by using the remaining life technique). Mr. Kaufman's proposal would not allocate the Company's costs over the service lives of its assets in a systematic and rational manner and, therefore, would not be consistent with the USofA. In addition, there is no explanation or rationale to support why a ten-year amortization period is appropriate and appears to be arbitrary. Thus, this argument lacks context and support.

Q. Mr. Kaufman claims that the theoretical reserve imbalance means that "future customers are receiving nearly free use" of assets.[6] Is he correct?

A. No. Mr. Kaufman's statement is based on one very small account that includes assets he refers to as possibly being "obsolete."[7] When one considers the rest of the Company's accounts, it is clear that Mr. Kaufman fundamentally misunderstands the Company's theoretical reserve imbalance. The theoretical reserve imbalance is developed over the entire history of the Company. It is not only the result of what current customers have paid but also many previous generations of customers. It does not mean that there have been intergenerational subsidies. Theoretical reserve imbalances arise as service life and net characteristics evolve over time and do not necessarily mean that any generation of customers "over-" or "under-paid."

[6] Kaufman, p. 11, line 16.
[7] Kaufman, p. 11, line 4.

Q. On pages 10 to 12 of his testimony, Mr. Kaufman discusses Account 373.07, Sentinel Lighting Equipment. Please address his discussion of this account.

A. Mr. Kaufman devotes a significant portion of his testimony on an account that is both unusual and represents a small fraction of the Company's assets. Specifically, the balance for Account 373.07 represents less than 0.1% of the Company's plant in service. It also has had minimal activity in recent years and has been relatively close to fully depreciated for many years. It is not reasonable to extrapolate the experience of this account onto the billions of dollars invested in other accounts that have considerably more remaining years to recover through depreciation.

Further, the specifics of the account do not support Mr. Kaufman's conclusions. For example, this account has had an accumulated depreciation reserve that is greater than the plant in service for the account since at least 2012, and remaining life depreciation rates corresponding to this have been relatively low as a result. Thus, customers have not "over-paid" depreciation in this account for many years. Mr. Kaufman's proposal would give an even greater subsidy to current customers by producing negative depreciation expense for this account for the next ten years. After that, customers would then have to pay higher depreciation rates. Yet, Mr. Kaufman observes that the assets in this account are possibly obsolete.[8] If this

[8] Kaufman, p. 11, line 5

is true today, it would make little sense for customers to pay, ten years from now, more than they have paid since 2012.

More important, a similar situation does not occur for larger accounts. Indeed, the other account Mr. Kaufman discusses – Account 356, Overhead Conductors and Devices – has over $84 million remaining to recover through depreciation expense and is, therefore, not at all comparable. In other words, the unique situation of Account 373.07 does not mean drastic measures are appropriate for other accounts. Indeed, if one were so inclined, a more targeted adjustment to Account 373.07 could be accomplished while having minimal effect on the other accounts that comprise more than 99.9% of the Company's investments. That is, Mr. Kaufman's observations about one isolated account in no way provide support for his much more significant proposal that affects every account.

Further, it should be noted that the TRI for most of the Company's depreciable plant accounts (as of the study date of December 31, 2019) is within a range that is reasonable. The TRI for depreciable plant in total is 19% and for most accounts does not exceed 30%. The select accounts that Mr. Kaufman uses to illustrate his arguments are not representative of most of the Company's accounts.

Q. Does the existence of a theoretical reserve imbalance suggest there is a problem that must be remedied?

A. No. The theoretical reserve and the theoretical reserve imbalance are the result of a calculation that incorporates many assumptions, and that the theoretical reserve itself is a simple model of the very complex history of transactions that have resulted in current accumulated depreciation balances. For this reason, the theoretical reserve almost never matches the book reserve. The mere existence of a theoretical reserve is a function of the difficulty of modeling real world utility property and forecasting service life and net salvage. The theoretical reserve should not be confused with the "correct" book reserve.

Q. If the theoretical reserve is not a perfect measurement of accumulated depreciation, why is it calculated?

A. The calculation of a theoretical reserve is not required, nor is it necessary, when using the remaining life technique and is not used in the remaining life formula. Some analysts do not even calculate the theoretical reserve when performing depreciation studies that are based on the remaining life technique.[9] While the theoretical reserve can serve as a rough benchmark as to how current estimates compare to depreciation estimates and plant and reserve activity in the past, it should not be considered the "correct" reserve. Authoritative depreciation texts are clear that the status of the book reserve as compared to the theoretical reserve is not a prescription for necessary adjustments to the reserve.

[9] Gannett Fleming's calculations use the theoretical reserve for each vintage of plant to allocate the book reserve to each vintage. However, the theoretical reserve is not used as a basis for any other remaining life calculations. Other depreciation software does not allocate the book reserve to the vintage, and thus does not use the theoretical reserve for the calculations.

Q. What do Mr. Kaufman's claims assume?

A. There are two important implicit assumptions inherent in his claims that we will discuss here. These assumptions are:

1. Estimates made today are completely accurate.
2. Previous depreciation rates for the Company, as accepted by the Commission, were "incorrect."

We will begin with the first assumption, as the problems with this assumption help to demonstrate some of the problems with the second.

Q. Is the assumption that estimates made today are completely accurate, a valid assumption?

A. No. The estimation of depreciation is a very complex and difficult task requiring the forecast of events (e.g., retirements and net salvage) that will take place in the future. Because the future contains a great deal of uncertainty, the assumption that these estimates are completely accurate is not reasonable.

Q. Do any authoritative sources support that assessment?

A. Absolutely. Again, NARUC states that:

> Instances occur where subsequent experience shows the original estimates no longer to be appropriate. It should be noted that only after plant has lived its entire useful life will the true depreciation parameters become known.[10]

[10] NARUC, p. 189.

Thus, NARUC is quite clear that estimates should not be considered completely accurate. It follows that the existence of a theoretical reserve imbalance should not be considered intergenerational inequity. Frank K. Wolf and W. Chester Fitch's *Depreciation Systems* (Wolf and Fitch) is another highly regarded, authoritative depreciation text. Wolf and Fitch also comment on the matter, stating:

> The CAD [theoretical reserve] is not a precise measurement. It is based on a model that only approximates the complex chain of events that occur in an actual property group and depends upon forecasts of future life and salvage. Thus, it serves as a guide to, not a prescription for, adjustments to the accumulated provision for depreciation.[11]

Given the complexities and uncertainties involved in estimating the future, we should not assume that the estimates in a depreciation study are completely accurate (which is an assumption inherent in Mr. Kaufman's proposal). They are the best estimates given the best information available, but we will not know for sure that they are correct until the plant has lived its entire useful life.[12] In future studies shorter lives or more negative net salvage may be appropriate, at which point a large negative theoretical reserve imbalance (or reserve deficiency) would develop if Mr. Kaufman's proposal was adopted. This would result in an even larger increase in rates (whether the

[11] *Depreciation Systems* (1994), Frank K. Wolf and W. Chester Fitch, p. 86.
[12] To put this in context, the average service life estimates in the depreciation study for many accounts are in the 50 to 60-year range. These are only averages though, and the estimates mean that some plant will last longer than 100 years. Thus, based on the service life estimates in the depreciation study, we will not know for certain if the estimates are correct for over 100 years.

remaining life technique or another reserve amortization were used). The remaining life technique provides for more stability in rates by allocating costs over the remaining lives, whereas Mr. Kaufman's approach would lead to much more volatility.

Q. Please address the second assumption inherent in Mr. Kaufman's position that prior estimates were "incorrect."

A. An understanding that the accuracy of depreciation estimates is unknown until all plant has lived its full useful life demonstrates the fallacy of the assumption that the existence of a reserve imbalance means that prior estimates were wrong and previous customers are subsidizing costs for future customers. To make such an assumption inherently assumes that today we have perfect knowledge of the future, which is an unrealistic assumption. Yet this is implicit in Mr. Kaufman's recommendation to amortize the theoretical reserve imbalance over a relatively short period of time.

Wolf and Fitch explain that the theoretical reserve is a simple model of a "complex chain of events." Many of the simplifying assumptions[13] inherent in the theoretical reserve model are not necessarily reasonable assumptions regarding actual real-world experience.

Q. What assumptions are inherent in the theoretical reserve model?

[13] The assumptions discussed here are related primarily to assumptions regarding life characteristics. However, one assumption made regarding the way net salvage is normally calculated in the theoretical reserve is that average and future net salvage are equal. This is in fact often not the case, and future net salvage is typically greater than average net salvage. The effect of this assumption is therefore normally to understate the theoretical reserve and overstate an estimated theoretical reserve "excess."

A. One key assumption is that all vintages of plant have the same life characteristics. While the depreciable groups studied in a depreciation study (based largely on the FERC USofA) are relatively homogeneous, there is variety within the accounts and not all assets, much less vintages of assets, will necessarily have the same life characteristics. For example, different materials may have been used for overhead conductors at different periods of time. If these different materials have different life characteristics, then the service life estimates will change naturally over time as the composition of types of assets in the overhead conductors account changes over time. For this reason, service life estimates today may be longer than would have been appropriate ten or twenty years ago. Because the service life estimate for the account is estimated for assets in service today, this natural change would result in a theoretical reserve imbalance due to the changing life characteristics over time. However, this does not necessarily mean that previous depreciation rates were too high, as Mr. Kaufman implies. Instead, it simply means that the life characteristics for the account are dynamic and have changed over time. In other words, given that different vintages of plant can have different life characteristics, it is incorrect to assume that the life estimates made today should have applied in the past for the entire history of the Company. Yet this is an assumption of the theoretical reserve model and an assumption Mr. Kaufman makes in his recommendation for the theoretical reserve imbalance.

Q. Are there other assumptions inherent to the theoretical reserve model?

A. Yes. Another assumption is that life characteristics do not change over time. We have explained that different vintages of plant can have different life characteristics. However, the life characteristics themselves can change over time as well. For example, operational practices, maintenance practices, and management decisions can change life characteristics over time. A good example is meters. An estimate that meters would last for 30 years was a reasonable estimate three or four decades ago. However, experience has shown that this was not a reasonable assumption ten years ago. The assets themselves did not change - the electromechanical meters 30 years ago were similar to those in service ten years ago - and the physical characteristics of these meters did not change. However, other considerations such as functionality or technology did change, which resulted in a significant change in life characteristics. This example illustrates that life characteristics do change over time and the theoretical reserve is far too simplistic an assumption from which to draw the conclusion that previous depreciation rates resulted in an overpayment.

Q. Do you have further comments related to the claim that previous depreciation rates were too high?

A. Yes. The Company's historical depreciation rates have been based on periodic depreciation studies in which the Company has presented what it considers to be the best estimates of depreciation based on the information available at the time. Other parties have also had the opportunity to present their estimates based on the same information. The Commission has concluded that the depreciation rates used by the Company were reasonable based on the information available at the time. That is, the book reserve for PGE is based on the depreciation rates that the Commission has historically recognized to be just and reasonable.

III. SERVICE LIFE ESTIMATES

Q. Does Mr. Kaufman propose changes to the service lives determined in the Stipulation?

A. Yes. He proposes changes to the survivor curve estimates for the accounts shown in the table below. The Stipulating Parties note that, with the exception of Accounts 352 and 356, these are interim survivor curve estimates, and the overall service life is also determined based on an estimated retirement date. Except for the Sullivan hydro plant, Mr. Kaufman has not recommended changes to the retirement dates for production facilities.

ACCOUNT	STIPULATION ESTIMATE	AWEC PROPOSED ESTIMATE
311	90-S1.5	98-R3
332	105-R3	120-R3
341	70-R3	80-R3
341.01	40-R4	50-S3
344.01	30-R3	38-R4
345	50-R2.5	60-R3
345.01	30-S2.5	45-S2
352	70-R2.5	75-R2.5
356	65-R2.5	70-R2.5

Q. Do you agree with Mr. Kaufman's proposed changes to the estimates for these accounts?

A. No. Mr. Kaufman's estimates are based primarily on the mathematical fit of the curves to the available historic data and do not adequately consider the many other factors that contribute to selection of an estimated survivor curve.

Q. Can you provide an example of how Mr. Kaufman's estimates are not appropriate?

A. Yes. For account 311, Mr. Kaufman's basis for the 98-R3 estimate is a statistical fit of one of the historical experience bands provided in the study along with the support that some (less than half) of the estimates used for companies in the industry statistics are over 100 years for this account. While these factors are worth consideration, they do not include all available information that is relevant to a curve estimate and belie an understanding of the conditions specific to the account in this case. Survivor estimates are intended to model the expected conditions for the account in the future. In making an estimate for this account, for example, it is worth considering that the only assets remaining in the account are those at the Colstrip location, which for purposes of depreciation, has an economic life that ends 2025, should the Commission adopt the Stipulation.

Mr. Kaufman's analysis is focused primarily on the Company's historic data and fitting curves to these data sets. It does not appear to give any consideration to what the future expectations might be for these accounts.

Q. Do authoritative depreciation sources support your assertion that a comprehensive depreciation study should incorporate factors other than statistical analysis?

A. Yes. All depreciation texts are clear that service life estimates are forecasts of future expectations. It is widely understood by depreciation professionals that exclusive reliance on the statistical analysis of historic data is inappropriate for life estimation. NARUC's *Public Utility Depreciation Practices* specifically discusses the impropriety of solely relying on mathematical analysis of historic data. It further discusses the subjective nature of life estimation.

> Actuarial analysis objectively measures how the company has retired investment. The analyst must then judge whether this historical view depicts the future life of the property in service. The analyst takes into consideration various factors, such as changes in technology, services provided, or capital budgets.[14]

NARUC also states:

> The reason for making an historical life analysis is to develop a sufficient understanding of history in order to evaluate whether it is a reasonable predictor of the future.[15]

Q. Have the estimates agreed to by the Stipulating Parties taken into consideration other factors besides the statistical analysis of historic data?

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[14] National Association of Regulatory Utility Commissioners, *Public Utility Depreciation Practices*, 1996, p. 111.
[15] National Association of Regulatory Utility Commissioners, *Public Utility Depreciation Practices*, 1996, p. 126. Emphasis added.

A. Yes. The estimates agreed upon by the Stipulating Parties were based on the Depreciation Study that has considered not just the historic data analysis but the Company's practices and expectations for the future, the current practices within the electric industry and knowledge of estimates used by other electric companies. Further, the Stipulating Parties have knowledge of the Company and its history and have collectively agreed upon the estimates provided in the Stipulation which are rooted in estimates that have been accepted by parties in prior cases for PGE.

Q. What change does AWEC propose for the Sullivan production facility?

A. Mr. Kaufman recommends extending the expected retirement date for this facility by 30 years to 2065 based on the potential for relicensing.

Q. Do you agree with the proposed change in retirement date to the Sullivan facility?

A. No. While PGE has general plans to relicense this facility in the future, the facility is currently licensed to operate through 2035. It is common practice in the industry to use the license date to establish estimated retirement dates for hydro facilities. As a facility nears its license date, it may be reasonable to expect a relicensing of the facility. However, this typically occurs within a few years of the license expiration when it is more certain that relicensing will be sought and approved. For Sullivan, the current license does not expire for another 14 years. Over the next 14 years, many things could change which could affect the outlook for the facility. As a result, it is premature to extend the retirement date for the Sullivan facility.

Q. What change does AWEC propose for account 344.01 – Wind generators?

A. Mr. Kaufman recommends a 38-R4 type curve that assumes an average service life of 38 years for wind generators.

Q. Do you agree with the proposed change for account 344.01 – Wind generators?

A. No. Although not clearly described in AWEC Exhibit 100, AWEC's statistical analysis appears to be based exclusively on PGE plant data. However, to estimate the average service life for wind generators, additional factors should be considered since PGE's 12-years history for this account is not sufficient data. As described in the depreciation study PGE estimated service life parameters for all depreciation accounts, including Account 344.01, after "compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived."[16] Through this procedure PGE estimated a 35-R3 survivor curve for Account 344.01.

Q. What was OPUC Staff's proposed survivor curve type for Account 344.01 average service life?

[16] See Depreciation Study, Section I-4

A. As previously described in the Stipulating Parties Exhibit 100 at page 7, Staff evaluated PGE's curve life combination in a statistical model and proposed a 25-R1 survivor curve for Account 344.01, which is within the range of majority industry statistic and meets the wind power industry expectation.

Q. Did the Stipulating Parties reach an agreement for Account 344.01 survivor curve?

A. Yes. As described in the Stipulating Parties Exhibit 100 at page 8, in settlement discussions, PGE emphasized the minimal retirements in the early service life for this type of assets due to parts' warranties and the significant statistical support for specified industry ranges. After this discussion, the Stipulating Parties agreed to utilize a 30-R3 curve that reflected all the critical factors for life expectancies for PGE's generator wind assets.

Q. What is your recommendation related to AWEC's proposed service life changes?

A. The Stipulating Parties recommend rejecting the service life changes proposed by Mr. Kaufman, on behalf of AWEC, in favor of the estimates agreed upon in the Stipulation.

IV. NET SALVAGE ESTIMATES

Q. Does AWEC propose changes to the net salvage estimates determined in the Stipulation?

A. Yes. He proposes changes to the net salvage estimates for the Transportation Equipment accounts shown below.

ACCOUNT	STIPULATION ESTIMATE	AWEC PROPOSED ESTIMATE
392.04	15%	18%
392.05	15%	18%
392.06	15%	18%
392.08	15%	18%
392.09	15%	18%
392.10	15%	30%

Q. Do you agree with Mr. Kaufman's proposed changes to the net salvage estimates for these accounts?

A. No. As with his life estimate proposals, Mr. Kaufman's net salvage estimates are based primarily on historic data and do not include consideration of relevant factors such as the Company's practices and outlook.

Q. Does Mr. Kaufman's approach to net salvage differ from that used in the Depreciation Study?

A. Mr. Kaufman's approach to net salvage is not significantly different from that used in the Depreciation Study; however, he did choose to segregate the helicopter subaccount for the purposes of net salvage analysis. The Depreciation Study analyzed the historic net salvage data for all Transportation Equipment subaccounts together to determine a single net salvage estimate to be applied to all the accounts.

Q. Is it necessary to segregate account 392.10 (Helicopter) for the purposes of estimating net salvage?

A. No. Due to the limited historic data available related to each of the Transportation Equipment subaccounts, the data for all 392 subaccounts were studied together for the net salvage analysis. Given that all assets within these accounts are treated similarly in terms of the Company's policies and outlook, this is a valid approach to analysis. Further, given the percentage of the total depreciable plant that the Transportation Equipment accounts comprise (less than 1%), there is limited effect on depreciation when using a single net salvage estimate for all of the 392 accounts versus estimating net salvage for them individually.

Q. What is your recommendation related to AWEC's proposed net salvage changes?

A. The Stipulating Parties recommend retaining the net salvage estimates agreed upon in the Stipulation as they are based on not just the historic net salvage recorded by the Company, but also on PGE's future expectations for these assets.

V. MR. KAUFMAN'S CRITICISMS OF SUPPORT FOR THE STUDY AND DEFICIENCIES WITH HIS PROPOSALS

Q. Please address Mr. Kaufman's criticisms of the Depreciation Study.

A. Mr. Kaufman criticizes the support of the Depreciation Study and makes recommendations for what he believes should be included in future filings. It should be noted that the Depreciation Study report is consistent with studies previously filed with the Commission and with numerous studies Gannett Fleming has performed across the country. Also, all parties to the Stipulation reached an agreement based on the Study as filed, and Mr. Kaufman's concerns were not raised by any other party in reaching the Stipulation agreement. Furthermore, all parties, including AWEC, had an opportunity to request direct testimony from PGE when the procedural schedule was discussed and agreed upon between parties. AWEC did not raise this issue at that time and agreed with the procedural schedule as adopted by the Administrative Law Judge.

The Study included the recommendations for each account along with supporting calculations and analyses used in determining the recommended service lives, net salvage, and depreciation rates. Additionally, Staff organized a workshop wherein PGE's depreciation consultant, John Spanos, gave an overview of PGE's filing with explanations of the methods, procedures, and techniques used to determine the depreciation rates. There was time for questions and comments. PGE has also responded to numerous data requests to provide additional materials that were used in support of the proposed depreciation parameters. This degree of support is not true for Mr. Kaufman's proposals. His testimony does not appear to include his recommended depreciation rates. As a result, it is not possible to review his recommendations and assess whether they are valid; and therefore, his testimony lacks the context and support needed to justify that his proposed depreciation parameters are fair, just, and reasonable.

Q. DO THE DEFICIENCIES IN MR. KAUFMAN'S TESTIMONY AND SUPPORT CREATE ISSUES WITH REVIEWING HIS PROPOSALS?

A. Yes. The deficiencies in Mr. Kaufman's testimony and support are particularly important because Mr. Kaufman's recommendations related to the Company's book reserve should result in modifications to the calculation of depreciation rates for each account. Mr. Kaufman's proposal to amortize the theoretical reserve imbalance of each account means the depreciation rates should be modified to include his adjusted reserve. Failing to do so will not result in the full recovery of the Company's assets. A mathematically correct calculation based on Mr. Kaufman's proposal would result in higher depreciation rates than calculated in the Depreciation Study (which would be more than offset by Mr. Kaufman's amortization of the theoretical reserve imbalance). If Mr. Kaufman did not make this adjustment to the reserve used to calculate his depreciation rates, then his proposed depreciation rates, combined with his reserve transfers and amortization, will under-collect depreciation by more than $600 million. Mr. Kaufman did not provide the calculations needed to confirm whether his proposals are mathematically accurate.

There is a similar issue with Mr. Kaufman's proposal to roll the reserves forward for Accounts 373.07 and 392.10. Not only is this proposal inappropriate policy, but if it were to be done, then other parameters would also need to be updated to align with the calculation date. Most notably, the remaining life for these accounts would be shorter than it would be as of the Depreciation Study test year. Again, because Mr. Kaufman has not provided adequate documentation of the depreciation rates that result from his recommendation, his proposals cannot be sufficiently reviewed to confirm their correctness or validity.

In summary, there are reasons to believe that Mr. Kaufman has not properly incorporated his recommendations into the development of reasonable depreciation rates. Given that he has not provided supporting calculations – much less the actual depreciation rates he proposes – there is no way to confirm the reasonableness of his proposals. Thus, AWEC's proposed changes to the Stipulation agreement should be rejected.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Colstrip Enabling Study

Summary

The purpose of this study (Study) is to respond to the Oregon Public Utility Commission's (Commission) request for further analysis on the impact of the early removal of Colstrip from Portland General Electric Company's (PGE) portfolio. This Study provides an expansion of PGE's 2019 IRP Colstrip sensitivity analysis as well as estimates of near-term customer price impacts. Results from the portfolio analysis suggest the early removal of Colstrip reduces long term costs and economic risks, and the magnitude of those cost and risk savings increase as the portfolio removal date is accelerated. Revenue requirement analysis suggests that accelerating the capital recovery for Colstrip will increase near-term customer prices. These increases can be partially mitigated by extending the recovery period for environmental and decommissioning costs to better align with actual expenditures. In addition to the cost and risk impacts of Colstrip, it is also important to cite the positive impacts associated with reduction of greenhouse gas emissions from PGE's portfolio, which aligns with PGE's evolving customer expectations. These findings rely heavily on forecasts for an aging plant in a changing economic and policy landscape, assume the ability to acquire replacement capacity timely and at a reasonable cost, and assumes a non-adversarial end to the Colstrip co-owners' relationship and no adverse legislative or regulatory actions. While the shared ownership of Colstrip does not allow PGE to act unilaterally and requires unanimous agreement to shut-down a unit, this report is helpful for PGE as it plans for an eventual exit of the plant from its portfolio that mitigates customer and shareholder risks and minimizes customer price impacts.

Background

Consistent with the requirements of SB 1547, portfolio analysis in PGE's 2019 IRP reflected the depreciation of Colstrip Units 3 & 4 by the end of 2030 and the removal of the units from PGE's portfolio by the end of 2034. Additionally, the 2019 IRP included portfolio analysis sensitivities in which Colstrip was removed from PGE's portfolio at the end of 2027 in response to stakeholder requests.[1] The results of the 2019 IRP Colstrip sensitivities showed that the preferred portfolio's Reference Case cost could be lowered if Colstrip units were to leave PGE's portfolio at the end of 2027. These findings suggested there could be economic benefits to removing Colstrip from PGE's portfolio earlier than the end of 2034. The 2019 IRP noted that a full evaluation of potential actions related to Colstrip Units 3 & 4 would require consideration of cost recovery and customer price impact analysis that were not traditionally incorporated into IRP portfolio analysis.

In the 2019 IRP Final Comments, PGE included an update to Colstrip sensitivities' results due to the updated fuel supply contract and updated consultant estimates of depreciation costs.[2] However, there remained considerable uncertainty surrounding the future cost of operating Colstrip both at that time and at present. These factors include uncertainty surrounding carbon pricing legislation in Oregon, and continued operational uncertainty and costs, arising from PGE's limited ability to pursue unilateral

[1] PGE 2019 IRP Section 7.4.2
[2] LC-73 PGE Final Comments Section 5.2

actions related to Colstrip due to long-standing co-owner agreements. Within Final Comments, PGE proposed to conduct an enabling study that would delve into the potential customer rate impacts of options related to Colstrip Units 3 & 4, including, but not limited to, modified depreciation schedules.

Commission Order No. 20-152 acknowledging the IRP[3] accepted Staff, stakeholder and PGE's recommendation to expand the Colstrip IRP analysis and assess the customer price impact of an accelerated exit from the PGE portfolio. A proposed ownership sale, new coal contract and a Washington law requiring the removal of coal by 2025 have increased PGE and stakeholder interest in the plant and PGE appreciates the opportunity to discuss further with stakeholders.

Colstrip

Located in Colstrip, MT, the Colstrip Electric Station is a mine-mouth coal plant originally consisting of four boiler units. Units 3 & 4 began operation in 1984 and 1986 respectively, and each has a generating capacity of about 740 megawatts (MW). PGE's 20% ownership share in Units 3 & 4 represents an aggregated 297 MW of generation capacity. The current plant operator, Talen Montana, also has an ownership interest in Unit 3 and is currently seeking to purchase from Puget Sound Energy an additional 12.5% interest in Unit 4.

PGE entered into an Ownership and Operation Agreement (O&O Agreement) in May of 1982 that defined its rights and obligations relating to Colstrip Units 3 & 4. The O&O Agreement is a multi-party agreement that defines the voting requirements for a variety of actions including budget approval. The multi-party nature of the O&O Agreement limits PGE's ability to unilaterally make decisions or take actions at the plant or end its involvement in the plant.

As noted in Puget Sound Energy's 2017 IRP[4], key contractual provisions include[5]:

- *Ownership is as "tenants in common," without a right of partition, and the obligations of each owner are several and not joint.*
- *Assignment and ownership transfer to third parties is limited, with a right of first refusal for an existing owner to acquire any ownership offered for sale.*
- *The term of the agreements continues for as long as the units are used and useful or to the end of the period permitted by law.*
- *Each owner must provide enough fuel to operate its share of the units at minimum load.*
- *Failing to pay its share of project costs or failing to provide adequate fuel constitutes a default on the part of the owner.*
- *An owner must continue to pay its share of operating costs and coal costs until it has transferred its ownership to another entity.*
- *No single owner has the ability or right to shut down the plant, so to shut down and decommission any unit, all owners of that unit must unanimously agree.*

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[3] Commission Order No. 20-152, available here: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf
[4] https://www.pse.com/-/media/PDFs/001-Energy-Supply/001-Resource-Planning/IRP17_AppK_083017.pdf
[5] PGE is quoting Puget Sound's summary without adopting it.

- *The ownership contracts do not establish a "put" right for any owner.*

In addition to the O&O Agreement there is a Common Facilities Agreement and separate agreement governing the Colstrip Transmission System.

The current co-owners of Colstrip Units 3 & 4, before completion of the proposed Puget Sound Energy transaction discussed below, and their ownership percentages are as follows:

Co-owner	Unit 3 Share	Unit 4 Share	Total Share
Talen Montana	30%	0%	15%
NorthWestern Energy	0%	30%	15%
Puget Sound Energy	25%	25%	25%
PacifiCorp	10%	10%	10%
PGE	20%	20%	20%
Avista	15%	15%	15%

Puget Sound Energy (PSE), Avista, PacifiCorp (PAC), NorthWestern Energy (NWE) and PGE are all regulated utilities with costs to operate the plant included in retail customer prices as follows:

Co-owner	State	Depreciation End Year
NorthWestern Energy	MT	2042
Puget Sound Energy	WA	2025
PacifiCorp	WA, OR, ID	OR- 2027[6], WA- 2023
PGE	OR	2030[7]
Avista	WA, ID	2025

Unlike the regulated utilities, Talen Montana recovers its costs to operate the plant through sales of its share of generation to wholesale power market participants. The diversity in co-owner business models, regulatory recovery timelines, legislation and stakeholders create an uncertain environment for potential Colstrip closure scenarios.

Recent Events

Unit 1 & 2 Closure

In June of 2019, Talen and PSE announced plans for a closure of Units 1 & 2 by the end of 2019, well ahead of the previously announced closure date of July 2022. While a bit delayed, both units ceased operations in January of 2020.

The closure of Units 1 & 2 has direct impacts on the cost to run Units 3 & 4. Many of the plant's facilities were shared among the four units and the closure of two units did not result in a material reduction to the cost to operate those shared, or common, facilities. The facilities were built to support the

[6] Not yet acknowledged by OPUC
[7] PGE may include in customer prices the costs and benefits associated with Colstrip through the end of 2034

operations of all four units and as units retire, these facilities are often less efficient and therefore more costly. As more units shut down these costs can increase leading to very challenging operating economics. The cost to operate Units 3 & 4 are continually evaluated by the co-owners to ensure efficient operations while also addressing the remaining efforts to support the decommissioning of Units 1 & 2 and common facilities.

The Clean Energy Transformation Act

The Clean Energy Transformation Act (CETA) was passed in Washington in 2019 and requires a Washington utility to eliminate coal-fired electricity from its state portfolio by 2025. Oregon has had Cap and Trade bills introduced at the legislature without success, but conversations continue about carbon limiting legislation in various forms including models like Washington's.

PSE Unit 4 Sale

It was announced in December of 2019 that PSE had entered into a transaction with NWE where it would sell its 25% ownership (185 MWs) in Unit 4 for $1. PSE will then enter into a Power Purchase Agreement (PPA) with NWE to purchase 90 MW of power for a term of approximately 5 years. The PPA will pay for approximately 50% of the $15 million increase in operations and maintenance and property taxes the increased ownership amount would result in for NWE. PSE would remain responsible for all legacy environmental and decommissioning obligations. In addition, PSE would sell an ownership interest in the Colstrip Transmission System representing 95 MW of capacity for book value[8]. In April of 2020 it was announced that Talen exercised its option under the O&O Agreement as a co-owner to join the transaction under the already negotiated terms[9]. If finalized, this would give each of Talen and NWE an additional 12.5% ownership interest in Unit 4, and the shares would appear as follows:

Co-owner	Unit 3 Share	Unit 4 Share	Total Share
Talen Montana	30%	12.5%	21.25%
NorthWestern Energy	0%	42.5%	21.25%
Puget Sound Energy	25%	0%	12.5%
PacifiCorp	10%	10%	10%
PGE	20%	20%	20%
Avista	15%	15%	15%

The PSE/NWE/Talen transaction also includes a vote sharing agreement which defines how the parties will vote, with respect to the vote currently controlled by PSE, under the O&O Agreement on items that are either specific to a unit or apply to both units.

[8] http://www.northwesternenergy.com/our-company/media-center/current/news-article/2019/12/10/NorthWestern-Energy-to-acquire-25-share-of-Colstrip-Unit-4-from-Puget-Sound-Energy
[9] https://www.mtpr.org/post/talen-energy-wants-colstrip-unit-4-purchase

Coal Supply Agreement

All Colstrip co-owners, except Talen, entered into a coal supply agreement with Westmoreland Mining LLC at the end of 2019 with a term covering 2020 through 2025[10]. This agreement solidified a fuel source for the plant after the bankruptcy of the former mine owner, Westmoreland Coal Co., created uncertainty about the operations of the mine going forward. Coal supply after 2025 remains uncertain and could result in additional cost.

PGE's 2020 AUT reflects the coal prices that were included in the Coal Supply Agreement finalized in December of 2019.

Regulatory Changes

In March of 2020, Avista received a Rate Case Order from the Washington Utilities and Transportation Commission (WUTC) adopting a partial multiparty settlement that included multiple Colstrip related provisions[11]. Both Units 3 & 4 depreciation schedules were accelerated to 2025 with decommissioning and remediation costs recovered over an extended timeframe reflecting the expected actual expenditure of those costs. Avista agreed not to support capital expenditures that extend the plant's operational life beyond December 31, 2025 and to fund a Colstrip Community Transition fund with $3 million. Transition funds are discussed in more detail below.

In July of 2020, WUTC issued a Rate Case Order that authorized a rate increase for PSE's electric operations.[12] Included in this rate increase was an acceleration of the recovery of Colstrip Units 3 & 4 to 2025 through updated depreciation schedules. The recovery of decommissioning and remediation costs were included in this schedule update with WUTC requiring PSE to track these costs separately for eventual true-up with actual expenses and further requiring PSE to file a recovery plan, including recovery timing, in its next GRC.

Current Oregon Colstrip Cost Recovery

SB 1547 established the current recovery mechanism for Colstrip, including accelerating capital recovery from customers by the end of 2030. In addition, PGE may include in customer prices the costs and benefits associated with Colstrip through the end of 2034 recognizing that exiting from the plant is challenging given the multi-party nature of the O&O.

The regulatory proceedings that define the current recovery for Colstrip related costs for PGE customers are the 2019 General Rate Case (GRC) and 2020 Annual Update Tariff (AUT) [13]. In addition, the impacts to customer prices of the 2021 AUT are still being determined under that proceeding. Since those dockets and absent an acceleration action, updates to cost estimates have occurred and those updates

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[10] https://westmoreland.com/2019/12/westmoreland-rosebud-mining-llc-announces-new-coal-supply-agreement-for-colstrip-units-34/

[11] Final Order 09, Dockets UE-190334, UG-190335, and UE-190222 (consolidated)

[12] Final Order 08, Dockets UE-190529 and UG-190530 (consolidated)

[13] General Rate Case: Final Order 18-464, Docket UE 335
AUT: Final Order 19-329, Docket UE 359

would be reflected in a new regulatory proceeding when filed resulting in a customer price increase if deemed prudent.

Environmental and Decommissioning Costs

The environmental and decommissioning costs included in the 2019 GRC will be updated to include the most recent studies under the Administrative Order of Consent (AOC) agreed to by the co-owners and Talen , as plant operator, and the Montana Department of Environmental Quality (MDEQ) to address ground water contamination on site. Those studies include a cost increase as approved by MDEQ of the Effluent Holding Pond Remedy Evaluation Report. Those updated amounts result in an approximate $47 million increase to PGE's obligation under the AOC compared to the 2019 GRC estimates. These numbers remain estimates with required remediation actions, including long-term monitoring, occurring beyond the closure of the plant for 50 years. PGE and all co-owners are responsible for the legacy environmental obligations and as the requirements around those obligations change, the impact to customer prices will also change. An example of a potential change in requirements could be a new administration introducing new standards for environmental cleanup.

Updated Capital Investments and Retirements

Since the 2019 GRC, the plant has continued to make capital investments and retire capital components as appropriate. These updated capital assumptions are continually changing and will require updating in PGE's next GRC.

Pension Obligations

Updated actuarial assumptions, market performance and funding plans continue to impact the cost of the pension PGE is obligated to fund under the O&O agreement. The O&O obligations to fund the pension continue beyond the plants exit from PGE's portfolio requiring flexible regulatory recovery.

Analysis Overview

The 2019 IRP included portfolio analysis of two sensitivities where Colstrip was removed from the portfolio by the end of 2027. This enabling study builds on that prior work by introducing additional scenarios and investigating customer price impacts in addition to long term portfolio cost and risk metrics. Because Colstrip has multiple co-owners subject to the O&O Agreement, the ability to effectuate a removal from PGE's portfolio is challenging. The analysis is presented as informational with the ability to accomplish any given scenario highly dependent upon a combination of regulatory, commercial, and/or legislative actions.

Results suggest that portfolio cost and risk decrease when Colstrip is removed from the portfolio. Further, these cost and risk reductions grow in magnitude as the removal date is accelerated. Revenue requirement analysis suggests accelerating the capital recovery for Colstrip will increase near term customer prices. These initial increases can be partially mitigated through extending the recovery period for environmental and decommissioning costs as well as potentially removing units from the portfolio on different timelines.

Scenarios

Consistent with the requirements of SB 1547, PGE's current cost recovery framework includes the recovery of depreciation through the end of 2030 and the requirement to have all costs removed from customer prices by the end of 2034. As part of this Study, PGE evaluated the following alternative scenarios:

Scenario	Depreciation End Year	Last Year in PGE Portfolio
2025	2025	2025
2025 (+4)	2025	2029
2027	2027	2027
2027 (+4)	2027	2031
Unit 3 2025, Unit 4 2027	Unit 3 2025, Unit 4 2027	Unit 3 2025, Unit 4 2027
Unit 3 2025, Unit 4 2030	Unit 3 2025, Unit 4 2030	Unit 3 2025, Unit 4 2030

As part of the customer price impact analysis, this report also includes a sensitivity that better aligns the recovery of environmental and decommissioning liabilities with actual expenditures. The overall impact of this sensitivity is that those dollars are recovered over a longer duration than the depreciation, which reduces the near-term impacts of a Colstrip acceleration decision on customer prices.

Customer Price Impact

This Study uses revenue requirement modeling methodology to estimate how the timing of Colstrip's removal from the Company's resource mix would impact customer prices. The scenarios evaluated in this Study are compared to the status quo, which includes full capital and environmental & decommissioning cost recovery by the end of 2030 and the full removal of Colstrip from customer prices by 2035. This base scenario uses the environmental and decommissioning costs per the 2019 GRC to illustrate a critical point: *even without an acceleration of Colstrip recovery, customer prices will increase due to the increased environmental & decommissioning costs.*

The Assumptions made in this study are summarized in Table 1 below. Compared to the analysis in the 2019 IRP, this model includes key updates to the environmental and decommissioning cost, operations and maintenance budgets, transmission tariffs, book value, tax value, depreciation and financial parameters. These components change throughout the IRP process and have significant potential impacts to customer prices.

Table 1: Customer Price Analysis Assumptions

Customer Price Analysis Assumptions[14]	
Start Year	2022
Future Wholesale Market Price Vintage	2019 H2[15]
Carbon Pricing	Consistent with the 2019 IRP, carbon pricing starts in 2021 and is included in all scenarios

[14] These assumptions apply to the Customer Price Impact section and not necessarily the Portfolio Analysis section.
[15] These prices were included in PGE's most recent avoided cost filing, Order 20-171, Docket UM 1728

	except those that are specified to not include carbon prices[16]
Financial Parameters	From Q2 2020
Operations and Maintenance Budget[17]	2020 Budget
Replacement Capacity	IRP proxy capacity resource[18]
Capital included in acceleration	Assets associated with the Colstrip plant, not the transmission system

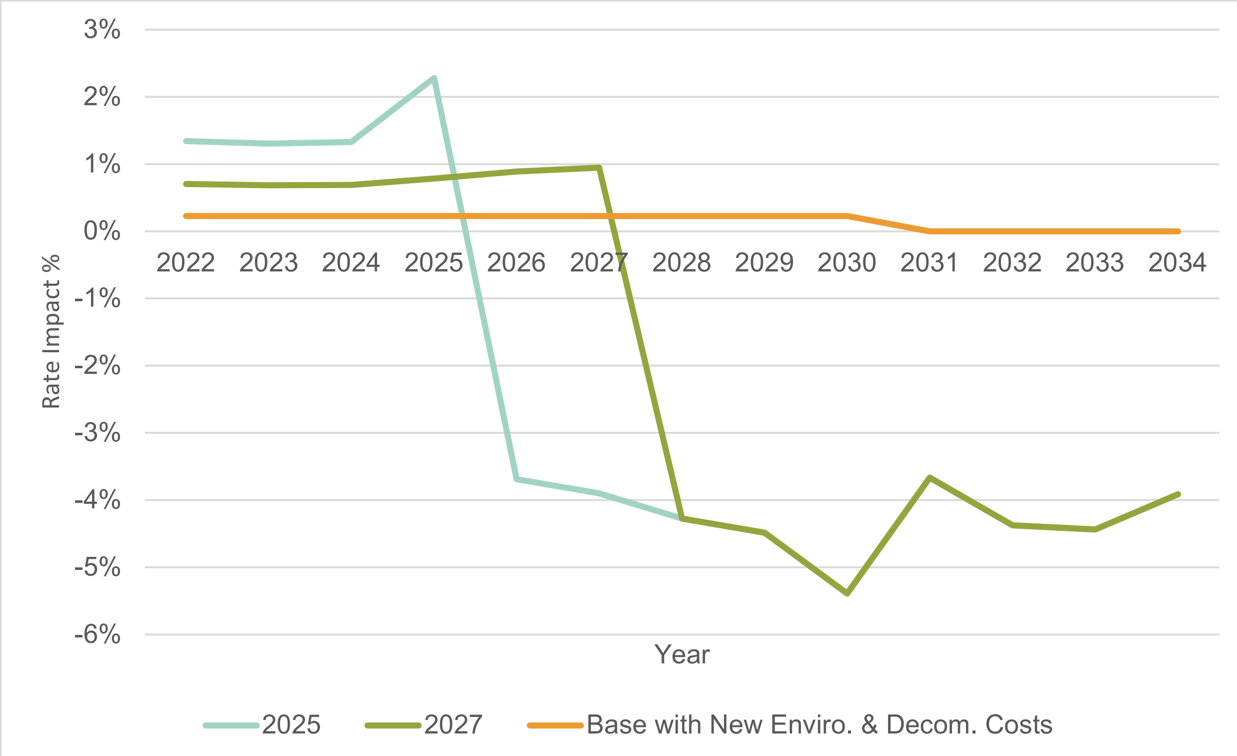
Results are expressed as the percentage customer price impact in any given year above or below the status quo and the amounts do not compound year over year. The denominator for this calculation is the estimated revenue requirement as of December 31st, 2021. This amount is held constant throughout the analysis as additional changes to customer prices are unknown at this time.

Accelerated Capital Cost Recovery

Accelerating the capital cost recovery may enable PGE to remove Colstrip from its portfolio at an earlier date, but it would have a near term customer price impact. Figure 1 below shows the impact to customer prices if PGE were to accelerate the depreciation of both units and remove the plant from customers prices in 2025 or 2027. This would require an updated schedule for the recovery of capital investment through depreciation. Both scenarios show a near term price increase representing the increase in depreciation required to fully recover the capital costs of the plant over a shorter period than currently contemplated in customer prices. After the units exit PGE's portfolio in 2025 or 2027, the analysis assumes that PGE would replace the capacity Colstrip provided with the proxy resource modeled in the IRP, a Simple Cycle Combustion Turbine (SCCT) with a levelized cost of $103/kW-yr. Replacing the plant with the proxy resource results in a price decrease in comparison to continued operations of Colstrip from 2025 or 2027 through 2034. This is because the proxy resource is anticipated to cost PGE's customers less than the continued operation of Colstrip. The base scenario in Figure 1 includes an increase to the status quo due to more current estimates of environmental and decommissioning expenses not yet included in customer prices.

[16] While it is unlikely that a carbon regime is realized starting in 2021, the analysis begins in 2022 when carbon pricing may still be realized through the 2021 legislative session. Additionally, PGE provides a sensitivity that examines customer price impacts without a carbon regime.
[17] The 2019 operations and maintenance budget is utilized across all scenarios to maintain consistency.
[18] See 2019 IRP, Section 7.1.1.1 - Resource Adequacy: https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2019-integrated-resource-plan.pdf?la=en

Figure 1: Accelerated Recovery Estimated Price Impact



The increase in price impact seen in 2025 in the 2025 scenario is due to the accelerated recovery of capital assets that are assumed to be put into service towards the end of the recovery window. There is a similar increase in the last year of recovery in the 2027 scenario, but it is not as large as estimated capital expenditures during that period are smaller based on current outage frequency and planning. The uncertainty around these capital investments and outages is high but because there are multiples owners of the plant, PGE is unable to unilaterally control budget decisions at any point along the plant's lifecycle.

An example of why there is uncertainty surrounding ongoing capital expenses is Avista[19] agreeing to not support projects that extend the plant's operational life beyond December 31, 2025. Other Washington utilities may also have similar realities and not support decisions to operate the plant beyond 2025. It is possible that the large repairs and outages forecasted today do not have the voting support required for implementation. In that instance the customer price increases in the 2025 and 2027 scenarios would not be as significant as there would be less capital to recover in the shortened time frame.

Continued Plant Operations Sensitivity

The current recovery mechanism established in SB 1547 allows for the recovery of non-capital Colstrip costs until the end of 2034, after the year it is fully depreciated. In line with the structure established in that legislation, PGE presents the impact on customer prices of keeping non-capital costs in customer prices four years after the plant is fully depreciated but notes that without a change in legislation this

[19] Final Order 09, Dockets UE-190334, UG-190335, and UE-190222 (consolidated)

option is available until 2034. These are the 2025 (+4) and 2027 (+4) scenarios. Figure 2 illustrates the price impact difference between continuing to operate the plant for four years after the units are fully depreciated and replacing the plant with another capacity resource after depreciation is complete. The capacity resource replacement is the same used in the 2019 IRP. While in this instance PGE's customers would see a savings compared to continued operation of the plant, there is no guarantee that a capacity resource would be available at that time and what the cost would be.

Figure 2: Estimated Price Impact of Continued Operations

Environmental and Decommissioning Expenses Extension

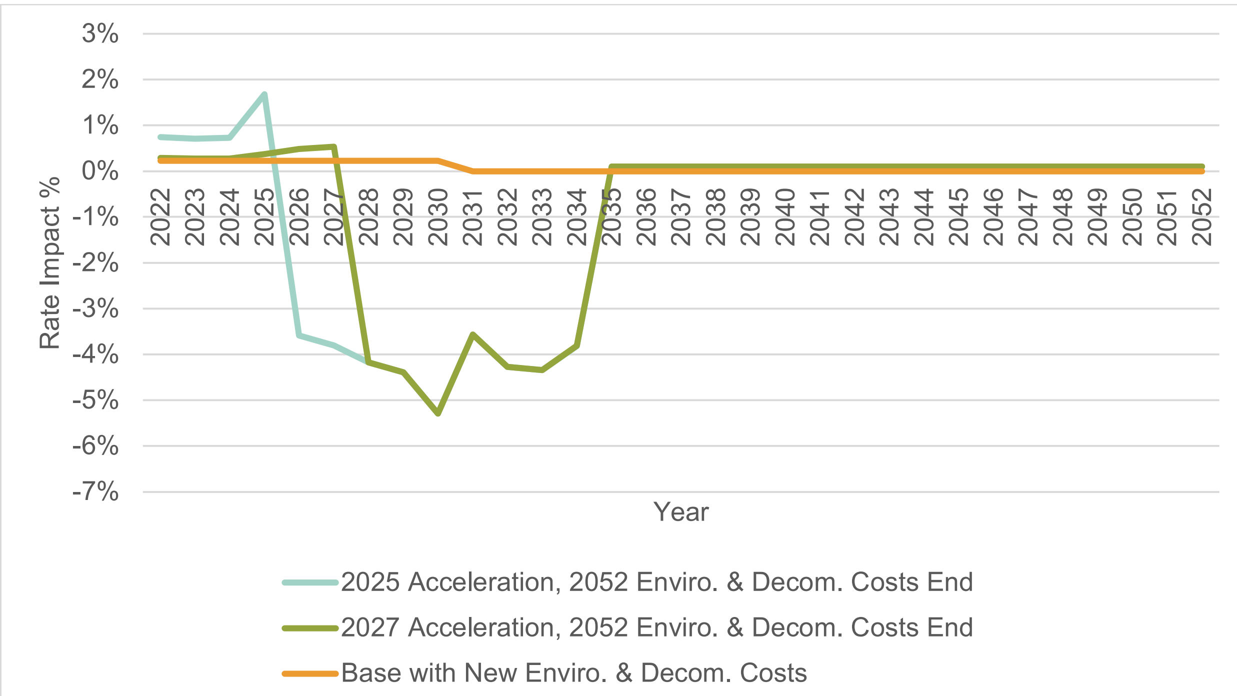
The environmental obligations and decommissioning expenses are a material consideration when evaluating customer price impacts. As addressed above, there has been a significant increase resulting from the MDEQ approving the estimated environmental and decommissioning costs associated with Colstrip, a change subsequent to the estimate included in the 2019 GRC and what is currently included in customer prices. The costs to remediate and decommission are likely to be incurred over an extended timeframe with current plans for expenditure over the next 50 years. A sensitivity to the analysis presented looks at the customer price impact if the recovery of decommissioning and remediation expenses occurred on a timeline that reflected the actual long-term nature of these obligations. For this sensitivity, PGE selected 2052 as the year to complete the recovery of environmental and decommissioning costs which is when most of the material expenditures are expected to have occurred. Extending the recovery reduces the near-term customer price impacts associated with the $47 million increase from the updated estimate of these expenses. By extending the timeline in which PGE recovers the decommissioning and environmental obligations until 2052, PGE estimates a decrease in the annual price impact percentage from 0.4%-0.6% depending on the acceleration scenario, as can be seen in

Table 2 and Figure 3 below. This decrease in comparison to the 2025 and 2027 scenarios is only during the capital recovery term and is the same amount each year until the capital is fully recovered.

Table 2: Reduction in Price Increase due to Extension of Environmental and Decommissioning Cost Collection

2022 Rate Impact % as Compared to Status Quo			
Capital Recovery End Year	Standard ARO Collection	Extended ARO Collection	Reduction in Price Increase
2025	1.34%	0.74%	0.60%
2027	0.70%	0.29%	0.41%

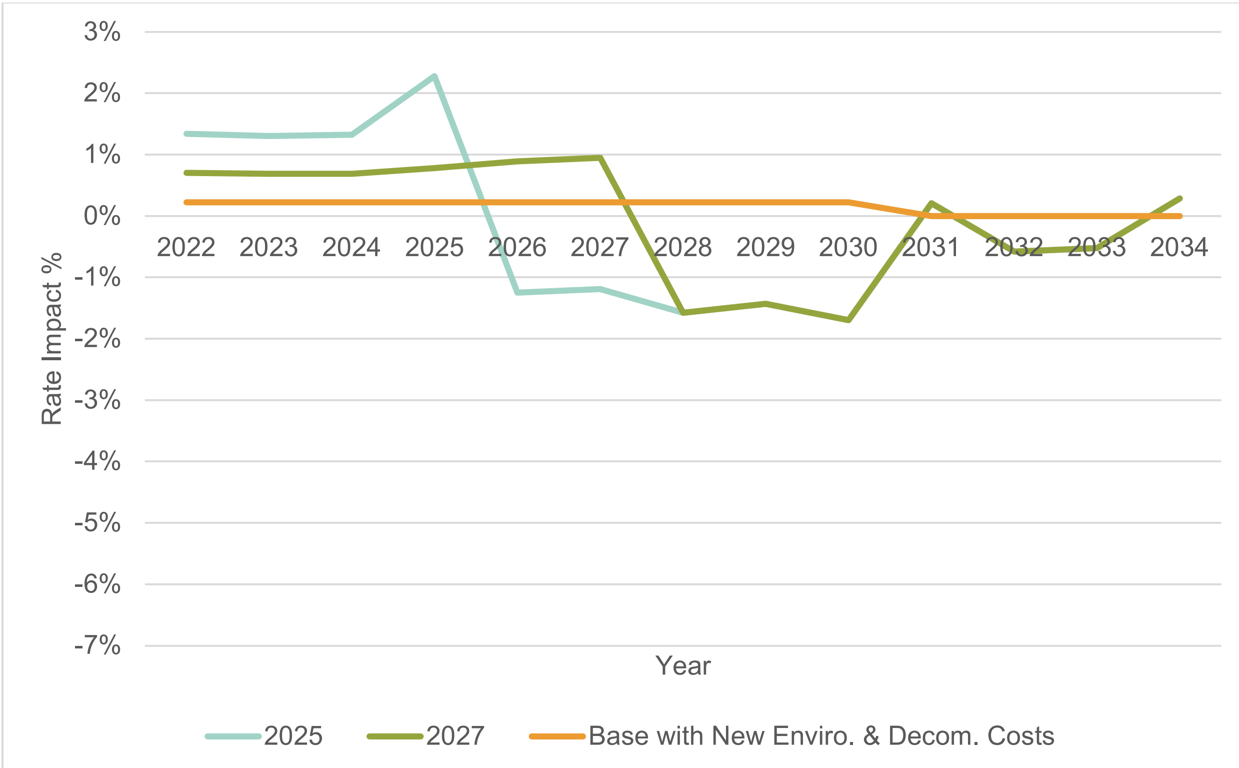
Figure 3: Estimated Price Impact of Extension of the Collection of Environmental and Decommissioning Costs



Carbon Price Assumptions

Colstrip's output is particularly sensitive to carbon pricing due to the high emissions rate of the plant. In scenarios with carbon pricing, Colstrip only dispatches, pursuant to its O&O Agreement, to its contractually required minimum generation level. To provide another perspective, the Company did additional analysis to include Colstrip's dispatch without the impact of carbon pricing. As illustrated in Figure 4 below, the near-term price impacts are similar to those with carbon pricing. The key difference occurs after the scenarios show Colstrip as fully depreciated and removed from customer prices. Since the plant would have been generating more MWhs and operating at a higher cost efficiency, replacing Colstrip with another resource in 2025 or 2027 is not as economic as it is when there is carbon pricing, but it still presents cost savings for customers compared to continued operation of the plant.

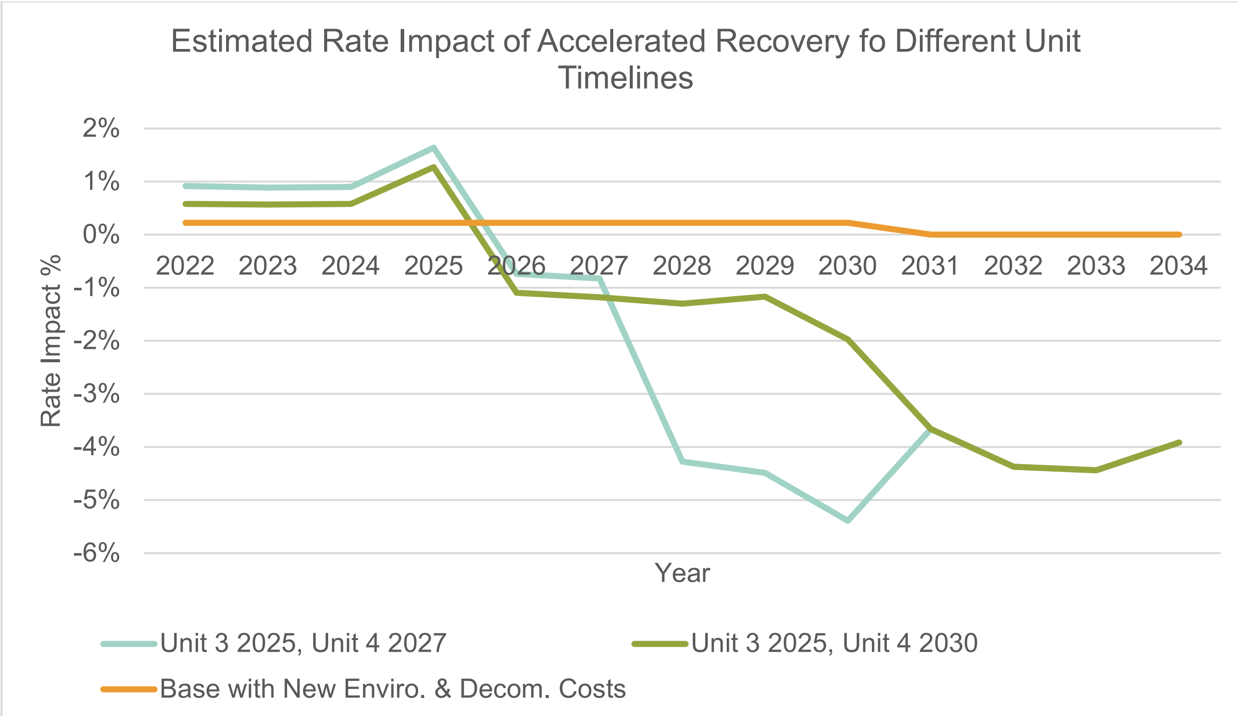
Figure 4: Estimated Price Impact of Acceleration with No Carbon Pricing



Individual Retirement Timelines for each Unit

Colstrip's co-owners have diversity in ownership, business practice, emissions goals, and regulatory processes. As a result, there could be an instance in which units 3 & 4 are removed from PGE's resource mix on different timelines. To investigate this option PGE looked at a scenario in which Unit 3 is depreciated and is removed from PGE's resource mix in advance of Unit 4. At this time the data to accurately estimate the cost of running one unit only is not readily available or easy to calculate due to uncertain impacts on shared and common facilities as well as workforce, so costs were assumed to be evenly split in the instance that one unit leaves PGE's portfolio before another. In practice, it is likely that running only one unit increases the cost of that unit due to lost efficiencies which may make the scenario impractical. Accelerating the capital recover for each unit on different timelines spreads the accelerated depreciation over a longer time horizon resulting in a lower year over year impact to customer prices.

Figure 5: Estimated Price Impact of Accelerated Recovery for Different Unit Timelines



Uncertainties

Overall, the results from all scenarios suggest that accelerating the capital recovery of the Colstrip units will yield price increases for customers that vary between 0.3%-2.4% during the years of the acceleration. Those increases can be reduced by extending the recovery timeframe for the asset retirement obligation and potentially having units removed from PGE's portfolio at different times. However, the figures provided in the Customer Price Impact portion of the study have a high degree of uncertainty because of the period of time examined. This customer price impact analysis relies on five and ten-year budget estimates from Talen, the plant operator. Long-term budgeting is inherently difficult and does not contemplate any unforeseen changes to plant operations or costs during a period of time in which Washington co-owners are legally required to remove Colstrip from their portfolios and other co-owners are anticipating a longer plant life. Additionally, changes in power market conditions and state legislation may change the plant dispatch and impact the cost to maintain.

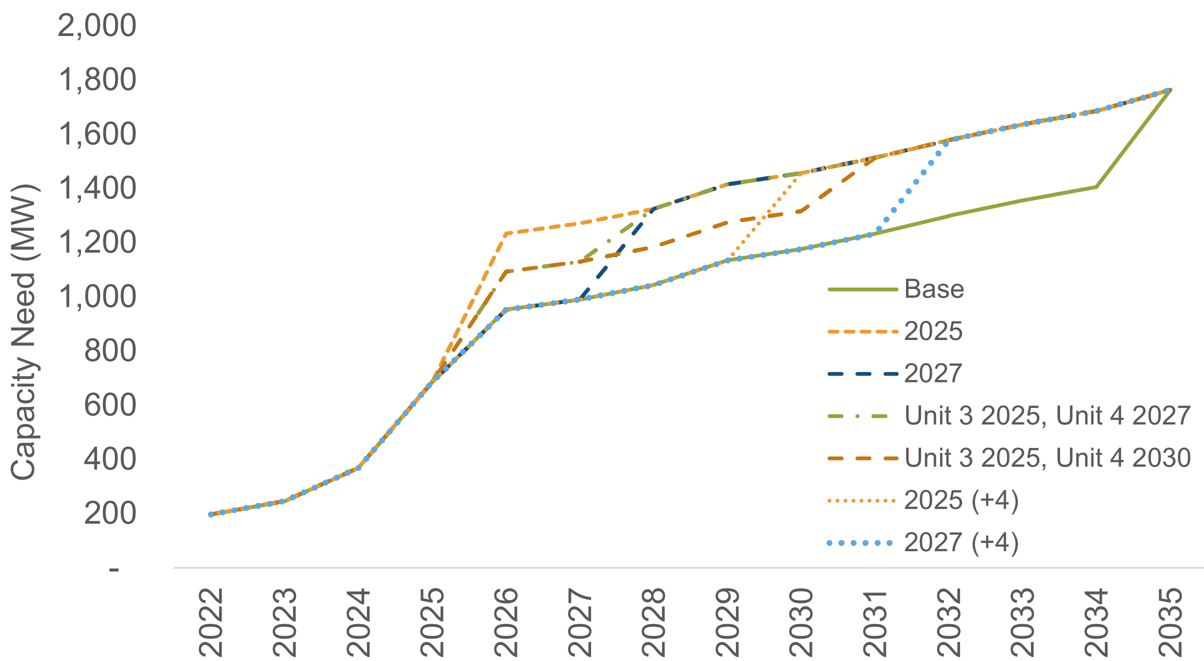
Portfolio Analysis

As discussed in the Background section above, sensitivities in which Colstrip units 3 & 4 were removed from the PGE Portfolio before the end of 2034 were included in both the 2019 IRP and LC-73 Final Comments. In addition to the expanded set of scenarios considered, this enabling Study also incorporates an update to natural gas price forecasts, which impact wholesale market prices, plant dispatch, and associated GHG emissions. [20]

[20] Natural gas prices were updated to the following: PGE 2020 Q1 forward gas trading curve from 2020-2024, Reference Gas Future of Wood Mackenzie 2019 H2 from 2025-2040, High Gas Future of 2020 U.S. Energy Information Agency (EIA) Annual Energy Output (AEO) Low Oil and Gas Supply Case from 2025-2040, Low Gas Future assumes gas prices grow at the rate of

The impact to PGE's capacity need in each sensitivity is shown in Figure 6. The acceleration of Colstrip's removal from PGE's portfolio to an earlier date in scenarios considered brings forward approximately 281 MW[21] of capacity need into the mid-2020's. This is a tangible impact, as this occurs when PGE is likely to experience increased capacity needs due to expiring contracts. Further, it occurs at a time when expected plant retirements will likely increase demand for capacity in the region.

Figure 6: **Capacity Need**[22]



Results

Results from the portfolio analysis consistently suggest that the acceleration of Colstrip's removal from PGE's portfolio lowers long term costs. The updated traditional cost and risk metrics of the preferred portfolio across each Colstrip scenario are shown below in Figure 7 and Table 3 below.[23] Under all scenarios, Reference Case costs are lower relative to the current exit date, as are both risk metrics.

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inflation from 2025-2040. All Gas Futures use 2025 as an interpolation year between the forward gas trading curve and subsequent forecasts. All Gas Futures assume gas prices grow at the rate of inflation from 2040-50. These assumptions are consistent with the 2019 IRP natural gas price treatment but have been updated to more recent forecasts. These prices were included in PGE's most recent avoided cost filing, Order 20-171, Docket UM 1728.

[21] The combined nameplate capacity of PGE's ownership shares in Colstrip Units 3 & 4 is 297 MW, however the estimated capacity contribution to PGE's system (which accounts for forced outage rates) is approximately 281 MW.

[22] The base capacity need used in this analysis is calculated from the filed 2019 IRP. The updated needs assessment filed in December 2019 (available here: https://edocs.puc.state.or.us/efdocs/HAH/lc73hah10211.pdf) slightly increased capacity need. Further updated capacity need information, to include the recently signed contract with Douglas County PUD, will be included in the next IRP Update. However, the magnitudes of the differences between the Base Case and each scenario reflected in this figure will remain the same, as these updates will affect each equally.

[23] For a detailed description of IRP portfolio metrics, please see Section 7.2.1 – Scoring Metrics from the 2019 IRP , available here: https://edocs.puc.state.or.us/efdocs/HAA/lc73haa162516.pdf

When the two Colstrip units leave PGE's portfolio in different years (e.g. 2025/2027), we see cost and risk metrics fall in between the cases where both units are removed from the portfolio in 2025 or 2027.

Given Colstrip's low forecasted dispatch, the evaluation of its removal from PGE's portfolio primarily involves the tradeoff between the fixed and variable costs associated with its continued operation and maintenance (O&M) and the cost of replacing its capacity. The results shown below are reflective of the fact that Colstrip's O&M costs escalate more rapidly than do the costs associated with replacement. Accordingly, earlier removal consistently leads to higher reductions in both Cost and Risk metrics.

Figure 7: Cost and Variability

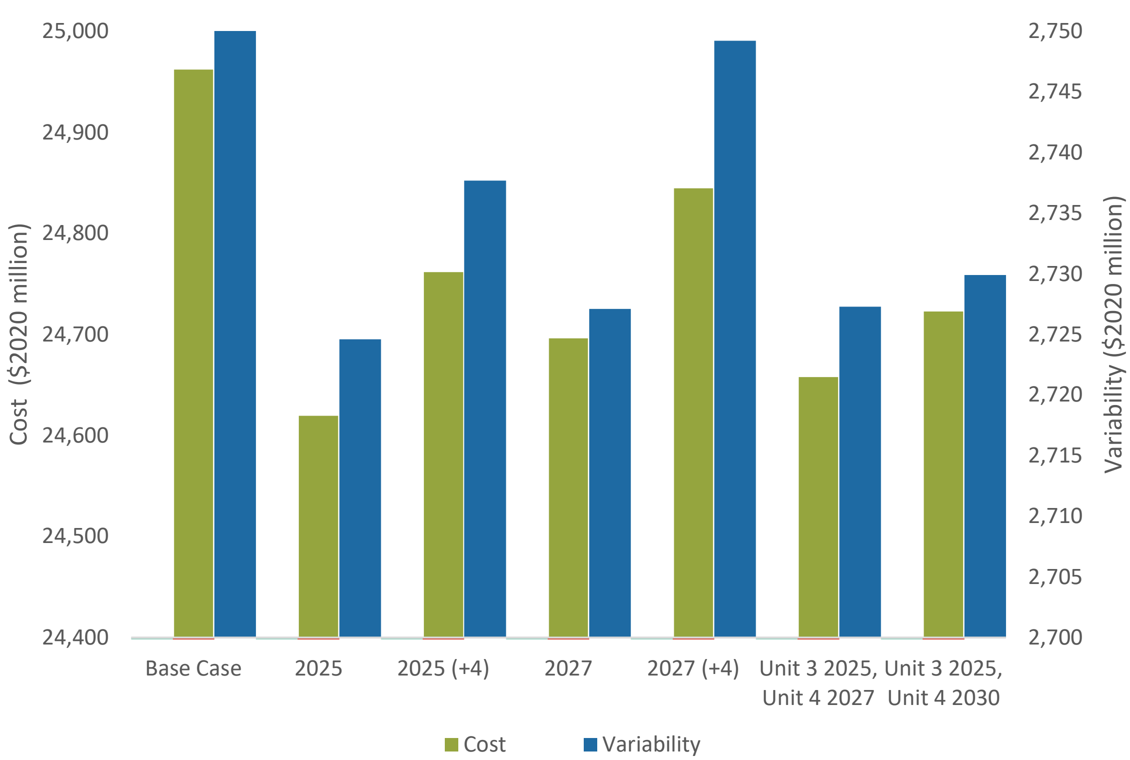
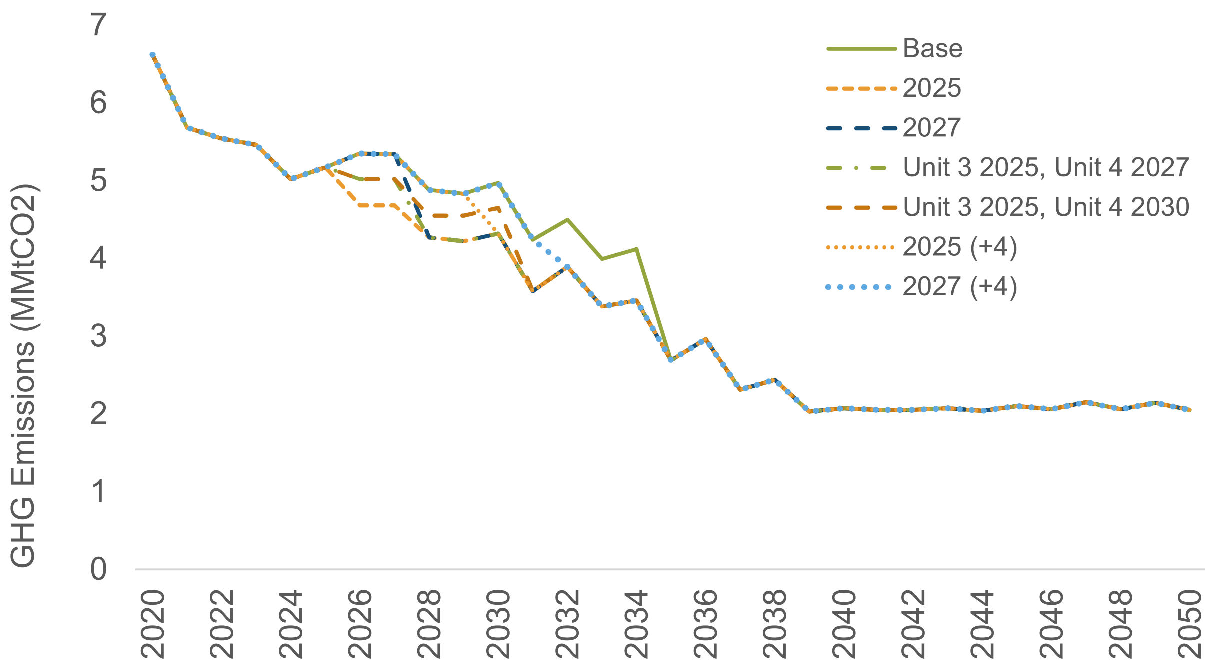


Table 3: Portfolio Scoring Metrics – Difference (Scenario - Base Case)

Scoring metrics (million 2020$)			
Scenario	Cost	Variability	Severity
2025	-343.0	-33.4	-370.8
2025 (+4)	-200.5	-20.3	-219.9
2027	-266.1	-30.9	-291.7
2027 (+4)	-117.5	-8.8	-129.2
Unit 3 2025, Unit 4 2027	-304.6	-30.7	-330.7
Unit 3 2025, Unit 4 2030	-239.5	-28.1	-261.3

Updated GHG emissions from the Colstrip sensitivities are included in Figure 8. Under Reference Case conditions, an early removal of Colstrip from PGE's portfolio continues to result in a reduction of GHG emissions relative to the Base Case.[24]

Figure 8: Emissions



Discussion

Beyond the portfolio costs and price impacts to customers, Colstrip has many subjective or non-quantifiable complexities and risks that require further discussion when determining the best balance of cost and risk for customers, the company, the town of Colstrip, Montana and the employees who work at the Colstrip plant who were integral in delivering many years of reasonably priced and reliable power to our customers.

Greenhouse Gas Emissions

The state of Oregon has set economywide greenhouse gas (GHG) emission reduction goals. HB 3543 (2007) established a 10% GHG reduction below 1990 levels by 2020 and 75% GHG reduction below 1990 levels by 2050. Executive Order No. 20-04 from Gov. Brown (March 2020) addressing climate change expanded these GHG reduction goals to at least 45% below 1990 levels by 2035 and at least 80% below 1990 levels by 2050. The Executive Order directs all state agencies to exercise their broad statutory authority to reduce GHG emissions and specifically directs the PUC to “Prioritize proceedings and activities, to the extent consistent with other legal requirements, that advance decarbonization in the

[24] The base case refers to the preferred portfolio estimated with the inputs and assumptions from the filed 2019 IRP and does not include any changes that have been made since then (such as the PPA with Douglas County PUD). These values will be updated in the next IRP Update.

utility sector." These actions demonstrate the state's commitment to reduce GHG emissions on an economywide basis and in the electric sector specifically. However, Colstrip and the removal of coal from Oregon utility customer prices is only explicitly addressed in SB 1547, which establishes the current framework for investment recovery (2030) and removal from customer prices (2034).

Accelerating the removal of Colstrip from PGE's portfolio certainly advances the state's GHG emissions reduction agenda and may reduce customer risk in a variety of future scenarios. Oregon has seen bills in the Oregon Legislature that would introduce a cap-and-trade program in the state, but the lack of a quorum in the last two legislative sessions has caused these bills not to advance. There is also conversation about a clean energy standard being advanced in the state as either a ballot initiative or introduced at a future Oregon legislative session. If either of these frameworks were to move forward it will increase the costs to run Colstrip once implemented. While the analysis presented in this Study does include some level of carbon cost, the exact details and timing of any future regime are unknown. For this reason, our analysis does not include specific costs or risks associated with the GHG emissions of Colstrip, however this will likely be an increasingly relevant consideration.

Customer Preferences

The Customer Insights Study, which was an enabling study from the acknowledgement of the 2016 IRP, illustrated that our customers, both residential and business customers, expect the Company to transition our resource mix towards more renewable resources. The study also found that coal was the least preferred resource for both PGE residential and business customers surveyed[25].

In addition to surveys to gain insights into our customer preferences, the Company has also seen an increase in local municipalities taking action to address the climate emergency. Of the 51 municipalities in our service territory, 12 have adopted climate action and/or sustainability plans, with other municipalities in active discussions of plan or goal development. Although these plans differ in scope and desired goals and outcomes, all seek to reduce greenhouse gas emissions from municipal operations and/or community-wide emissions. Of the plans and resolutions adopted to date within our service territory, the following municipalities have the most aggressive electricity decarbonization goals:

- Beaverton has committed to achieve net zero emissions for electricity by 2035;
- Milwaukie has committed to achieve net zero emissions for electricity by 2030;
- Portland has committed to meet 100% of community-wide electricity needs with clean, renewable energy by 2030; and
- Multnomah County has committed to meet 100% of community-wide electricity needs with clean, renewable energy by 2035[26].

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[25] https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/msi-customer-insights-study-rt-18-1-2018-02-14.pdf?la=en

[26] Beaverton: Page 32, https://www.beavertonoregon.gov/DocumentCenter/View/27980/Beaverton-Climate-Action-Plan---2019

Milwaukie: https://www.milwaukieoregon.gov/sustainability/climateaction

Removing coal from PGE's resource mix on an accelerated timeframe would be a key step for PGE to help its municipal customers achieve their clean energy goals.

Operational Considerations

The cost to operate and maintain the plant into the future remains uncertain. Material changes to the assumptions in the analysis can occur for a variety of reasons including post- 2025 coal supply costs, the impacts of unexpected repairs and maintenance costs, and increased costs from lost efficiencies upon unit closures.

As previously discussed, the current Coal Supply Agreement's term ends December 31, 2025. The Rosebud mine, the plant's current mine-mouth coal supply, is likely to reevaluate their cost structure, including potentially high cost access to new coal seams, and negotiate increased pricing with the co-owners. An alternative supply of coal would likely introduce additional plant investments and supply chain logistics resulting in higher overall operational costs.

Unit closures will continue to remove efficiencies from the operations of common and shared facilities making continued operations more expensive and potentially uneconomic.

The plant is over 35 years old and may experience outage events requiring repairs in excess of current and future budgets. These costs are not contemplated in the analysis and may be significant if incurred. With differences in co-owner cost recovery timelines and mechanisms, there may not be alignment in the appropriate level of maintenance, capital replacement or both.

Capacity and Resource Adequacy

The above portfolio analysis, consistent with PGE's acknowledged 2019 IRP, illustrates the material capacity need PGE forecasts beginning in the mid-2020's. While many of the assumptions are subject to change, including load projections and contract renewal status, an acceleration of the removal of Colstrip from PGE's portfolio increases needed capacity at a time when the resource adequacy of the region is in question. The analysis assumes replacement of the capacity using the IRP proxy resource but capacity constraints in the region and rapid technological change mean that there is significant uncertainty in future costs for capacity. There is value to customers in minimizing exposure to those uncertainties and there is value in having optionality as conditions change.

Reducing uncertainties will require a PGE commitment to replace the capacity that Colstrip has provided PGE's system for close to four decades[27]. This could be achieved through one or more actions and should contemplate leveraging the existing transmission rights from Colstrip to PGE's system to access high capacity renewables such as Montana wind for PGE customers. Montana wind represents a renewable resource that contributes more capacity to PGE's system (37% ELCC) than Gorge wind

Portland: Page 9, https://www.portlandoregon.gov/auditor/article/763389
Multnomah County: Page 3, https://multco.us/node/34287

[27] The needs associated with Colstrip exiting the portfolio are beyond the current IRP Action Plan and would require additional actions

projects (24% ELCC) or a solar and storage project (20% ELCC[28]) providing a unique opportunity to meaningfully address PGE's capacity need at the same time as acquiring low cost carbon free energy. A second action may require a commitment to a dispatchable resource to be able to ensure reliable supply for PGE customers. Consistent with the findings of the most recent IRP, PGE may consider existing dispatchable capacity or new non-emitting capacity resources, such as battery storage or pumped storage, to meet remaining needs.

Additionally, SB 1547 included a mechanism that allowed for recovery of non-capital costs beyond the date that it will be fully depreciated. With any change to the recovery of depreciation, continuing this mechanism allows optionality for customers to continue to access the plant's benefits helping to provide a capacity option to maintain a reliable power supply if needed.

Exit from PGE Portfolio vs Exit from Plant

As discussed above, the O&O Agreement does not provide any co-owner the ability to unilaterally decide when the plant closes and does not eliminate a co-owner's obligations to pay for fuel and operations until the plant closes. PGE's options for exiting the plant are limited given the plant's age, fuel source and location. The two main vehicles for a potential PGE exit from the plant are:

- Plant Sale - Innately challenged by having to recover remaining investment in plant through purchase price, legacy environmental obligations, and pension obligations. The current co-owner group are the most likely candidates for a purchase and the three Washington co-owners are precluded from recovering the costs of a coal plant beyond 2025.
- Plant Closure - A shutdown of either unit, or both, will require the approval of the co-owners and different recovery mechanisms, operational needs, and policy realities can make consensus on a certain year challenging. Additionally, the closure of one unit may significantly increase the operating cost of the remaining unit making the option challenging.

Commitment to the Colstrip Community (Transition Funds)

Transition funds are common for long-lived assets with large impacts to local communities. To date, Avista has committed $3 million and PSE $10 million[29] to help the people of Colstrip mitigate the economic impact of the plant's eventual closure.

In addition to the jobs that decommissioning and remediation obligations provide, PGE commits to do the right thing for the plant workers and the Colstrip community to address the implications our exit from Colstrip will have on the community that supported PGE and its customers for many years. It will be critical to partner with stakeholders, including labor and the Colstrip Community Impact Advisory Group, to explore options that balance the interest of workers at the plant, the local community and our

[28] See 2019 IRP, Section 6.2.3 – Capacity Value: https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2019-integrated-resource-plan.pdf?la=en

[29] https://dojmt.gov/colstrip-receive-minimum-10-million-community-impact-result-rate-case-settlement/

customers. When exploring those options PGE will consider the Colstrip agreements and the impacts that decisions related to Colstrip could have on communities in Montana.

Conclusion

This Study analyzed the impacts to PGE customers on both an overall portfolio cost and customer price impact basis and found that an acceleration of the removal from PGE's portfolio resulted in long-term portfolio cost savings but with near-term customer price impacts. Updates made to the environmental and decommissioning cost estimates since the last GRC will further increase those near-term price impacts. Extending the recovery of the decommissioning and environmental costs to more closely reflect the expenditures is one way to mitigate the price increase customers would experience with an acceleration action. Additionally, retiring each unit over different timeframes mitigates near-term price impacts but is challenged by needing unanimous co-owner approval[30] and may have costly operational realities.

While an acceleration action does advance the state's GHG emissions reduction agenda, it does so at a time when the resource adequacy of the region is in question and PGE is forecasted to have a significant capacity need.

PGE believes the optimal regulatory construct to provide the flexibility for the removal of Colstrip from PGE's portfolio given the multiple complexities to be a two-part solution. Flexibility to act is important but does not guarantee an exit from the plant.

1. **Acceleration of capital recovery to the end of 2025.** Analysis suggests the removal of Colstrip from PGE's portfolio in 2025 provides customers the greatest reduction in the IRP portfolio metrics of cost and risk. This date also aligns with Washington's CETA legislation and the current coal contract, better aligning PGE with several co-owners. Beyond 2025 the uncertainty at the plant materially increases and having the asset fully recovered by this date allows PGE and customers the most flexibility to be able to accommodate any future. This added flexibility will also allow PGE to pursue Montana wind projects that can leverage the Colstrip Transmission System in a more optimal timeframe.
2. **Recovering environmental and decommissioning expenses through the end of 2052.** Acceleration of capital recovery comes at the expense of near-term customer price impacts. Extending the recovery of the environmental and decommissioning expenses mitigates some of these price impacts and better aligns cost recovery with actual expenditures.

[30] Unanimous co-owner approval required for a closure of one or both units.

https://www.ecfr.gov/current/title-18/chapter-I/subchapter-C/part-101

Allowances acquired for speculative purposes and identified as such in contemporaneous records at the time of purchase shall be accounted for in Account 124, Other Investments.

B. When purchased allowances become eligible for use in different years, and the allocation of the purchase cost cannot be determined by fair value, the purchase cost allocated to allowances of each vintage shall be determined through use of a present-value based measurement. The interest rate used in the present-value measurement shall be the utility's incremental borrowing rate, in the month in which the allowances are acquired, for a loan with a term similar to the period that it will hold the allowances and in an amount equal to the purchase price.

C. The underlying records supporting Account 158.1 and Account 158.2 shall be maintained in sufficient detail so as to provide the number of allowances and the related cost by vintage year.

D. Issuances from inventory from inventory included in Account 158.1 and Account 158.2 shall be accounted for on a vintage basis using a monthly weighted-average method of cost determination. The cost of eligible allowances not used in the current year shall be transferred to the vintage for the immediately following year.

E. Account 158.1 shall be credited and Account 509, Allowances, debited so that the cost of the allowances to be remitted for the year is charged to expense monthly based on each month's emissions. This may, in certain circumstances, require allocation of the cost of an allowance between months on a fractional basis.

F. In any period in which actual emissions exceed the amount allowable based on eligible allowances owned, the utility shall estimate the cost to acquire the additional allowances needed and charge Account 158.1 with the estimated cost. This estimated cost of future allowance acquisitions shall be credited to Account 158.1 and charged to Account 509 in the same accounting period as the related charge to Account 158.1. Should the actual cost of these allowances differ from the estimated cost, the differences shall be recognized in the then-current period's inventory issuance cost.

G. Any penalties assessed by the Environmental Protection Agency for the emission of excess pollutants shall be charged to Account 426.3, Penalties.

H. Gains on dispositions of allowances, other than allowances held for speculative purposes, shall be accounted for as follows. First, if there is uncertainty as to the regulatory treatment, the gain shall be deferred in Account 254, Other Regulatory Liabilities, pending resolution of the uncertainty. Second, if there is certainty as to the existence of a regulatory liability, the gain will be credited to Account 254, with subsequent recognition in income when reductions in charges to customers occur or the liability is otherwise satisfied. Third, all other gains will be credited to Account 411.8, Gains from Disposition of Allowances. Losses on disposition of allowances, other than allowances held for speculative purposes, shall be accounted for as follows. Losses that qualify as regulatory assets shall be charged directly to Account 182.3, Other Regulatory Assets. All other losses shall be charged to Account 411.9, Losses from Disposition of Allowances. (See Definition No. 30.) Gains or losses on disposition of allowances held for speculative purposes shall be recognized in Account 421, Miscellaneous Nonoperating Income, or Account 426.5, Other Deductions, as appropriate.

22. Depreciation Accounting.

A. Method. Utilities must use a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property over the service life of the property.

B. Service lives. Estimated useful service lives of depreciable property must be supported by engineering, economic, or other depreciation studies.

C. Rate. Utilities must use percentage rates of depreciation that are based on a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property to the service life of the property. Where composite depreciation rates are used, they should be based on the weighted average estimated useful service lives of the depreciable property comprising the composite group.

23. Accounting for other comprehensive income.

A. Utilities shall record items of other comprehensive income in account 219, Accumulated other comprehensive income. Amounts included in this account shall be maintained by each category of other comprehensive income. Examples of categories of other comprehensive income include, foreign currency items, minimum pension liability adjustments, unrealized gains and losses on available-for-sale type securities and cash flow hedge amounts. Supporting records shall be maintained for account 219 so that the company can readily identify the cumulative amount of other comprehensive income for each item included in this account.

B. When an item of other comprehensive income enters into the determination of net income in the current or subsequent periods, a reclassification adjustment shall be recorded in account 219 to avoid double counting of that amount.

C. When it is probable that an item of other comprehensive income will be included in the development of cost-of-service rates in subsequent periods, that amount of unrealized losses or gains will be recorded in Accounts 182.3 or 254 as appropriate.

24. Accounting for derivative instruments and hedging activities.

A. Utilities shall recognize derivative instruments as either assets or liabilities in the financial statements and measure those instruments at fair value, except those falling within recognized exceptions. Normal purchases or sales are contracts that provide for the purchase or sale of goods that will be delivered in quantities expected to be used or sold by the utility over a reasonable period in the normal course of business. A derivative instrument is a financial instrument or other contract with all of the following characteristics:

(1) It has one or more underlyings and a notional amount or payment provision. Those terms determine the amount of the settlement or settlements, and, in some cases, whether or not a settlement is required.

(2) It requires no initial net investment or an initial net investment that is smaller than would be required for other types of contracts that would be expected to have a similar response to changes in market factors.

