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April 24, 2019

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PORTLAND GENERAL ELECTRIC CO.
Application for the Deferral of Storm-Related Restoration Costs
Docket No. UM 1817

Dear Filing Center:

Please find enclosed the Reply Testimony and Exhibits of Dr. Marc M. Hellman (AWEC/100 – AWEC/103) on behalf of the Alliance of Western Energy Consumers in the above-referenced docket.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1817

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
Application for the Deferral of Storm-Related Restoration Costs.	)
	)
	)

REPLY TESTIMONY OF DR. MARC M. HELLMAN

ON BEHALF OF THE

ALLIANCE OF WESTERN ENERGY CONSUMERS

April 24, 2019

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Dr. Marc Hellman. My business address is 2760 Eagle Eye Ave. NW, Salem, Oregon, 97304.

Q. PLEASE STATE YOUR OCCUPATION AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am an economist by training with significant experience in energy utility regulation. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I have a Masters and PhD in Economics awarded by Claremont Graduate School and a Bachelor's degree in both Economics and Mathematics awarded by California State Polytechnic University, Pomona.

With regards to my prior work experience, I was employed for 38 years in various capacities by the Public Utility Commission of Oregon, with the last twenty years or so in a management capacity leading economists, accountants and financial analysts in the review of utility general rate filings and rate proposals, financing and affiliated-interest applications, property sales, and merger and acquisitions. I have also provided consulting services for a varied set of clients including the Commonwealth Utilities Corporation with headquarters in Saipan, the Smart Energy Alliance in a Nevada Power general rate filing before the Public Utilities Commission of Nevada, the South Dakota Intrastate Pipeline Company for a general rate filing before the South Dakota Utilities Commission, and have begun work for the Renewable Energy Coalition and the Rocky Mountain

Coalition for Renewable Energy in a Wyoming QF-related docket. A copy of my work history is provided as Exhibit AWEC/101.

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. This testimony addresses the PGE deferral application regarding its 2017 Level III storm costs. On April 12, 2019, PGE filed corrected testimony reducing its deferral request from $9.4 million to $8 million. Unless otherwise explicitly noted, all references to PGE Direct Testimony are to that filed as a revision on April 12, 2019.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission deny PGE's request to establish a deferral. In prior comments to the Commission, AWEC indicated that it did not believe PGE's petition met the legal standard for a deferral. AWEC will expand on these arguments in briefing. My testimony shows that, regardless of the legal hurdles to PGE's request, its petition also does not meet the Commission's discretionary standard for granting a deferral, a standard that is well grounded in regulatory policy.

The UE 335 Commission order stated an openness to consider a deferral of the 2017 Level III storm if the costs were shown to be extreme or a result of climate change causing greater storm intensity.[1/] PGE has failed to demonstrate the former and never discussed the latter. While I recommend against it for reasons discussed below, if the Commission is to consider the magnitude of PGE's Level III storm costs relative to previous years' storm costs rather than relative to its costs overall, then with regard to an

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[1/] Docket No. UE 335, Order 18-464 at 14 (Dec. 14, 2018).

extreme storm event, the threshold for a deferral should be costs that at least exceed $8.6 million. PGE requests a deferral of only $8 million.

Additionally, in the event the Commission declines to approve PGE's application, I recommend the Commission direct PGE to accrue a credit, with interest, of $100,000 annually, for later return to customers.[2/]

Finally, in the event the Commission approves PGE's application to defer a portion of 2017 Level III storm costs, the Commission should direct PGE to recalculate the 10-year Level III storm cost average excluding the portion of the 2017 Level III storm costs allowed to be deferred, consistent with the methodology adopted in UM 1234, and accrue the difference from the $3.8 million that is currently in rates, with interest, for later return to PGE customers.[3/]

II. DISCUSSION

Q. PLEASE DESCRIBE THE REGULATORY RATE MECHANISM THAT RELATES TO PGE LEVEL III STORM COSTS.

A. PGE's Level III storm accrual mechanism was adopted in Docket No. UE 215 (Commission Order No. 10-478), and applies to Level III storm restoration costs. Under the rate mechanism, PGE accrues an amount of expected Level III storm costs equal to a

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2/ The $100,000 value is derived using PGE's corrected 2017 Level III storm costs of $10.6 million, versus the $11.4 million value used in UE 335. The revised 10-year Level III storm costs average is $3.7 million. The UE 335 Order adopted a 10-year Level III Storm cost average of $3.8 million based on an incorrect 2017 Level III storm cost of $11.4 million. The $100,000 value is calculated as the difference between $3.8 million and $3.7 million.

3/ In PGE's response to AWEC Data Request 002, attached hereto as AWEC/102, PGE provided an updated amount of calendar 2017 Level III storm total costs of $10.6 million, while the UE 335 2017 value was $11.4 million and used to derive the 10-year average value. The $11.4 million is escalated to 2019 dollars for purposes of deriving the $3.8 million average. The revised 10-year average Level III storm costs for use in UE 335 is $2.6 million using a $0 value for 2017 Level III storm costs.

10-year rolling average of PGE-recorded Level III storm costs. The rate mechanism allows positive, unspent balances to carry forward to future years. So, if the 10-year average of Level III storm costs was $2 million and PGE did not incur any Level III storm damage costs in a year (call it the first year), the full $2 million would be available to meet future Level III storm costs. Now assume in this illustrative example that in the following year (second year), Level III storm costs were $3 million. PGE would have the 10-year average of $2 million plus the $2 million carry-forward from the previous year. That means there would be $1 million carry forward to the following year (third year). ($2 + $2 - $3 = $1) The discussion excludes interest for ease of discussion.

It should be pointed out, however, that the Level III storm accrual mechanism does not allow for negative balances. The lowest value for the account is zero. Therefore, in the prior example, if in that second year, instead of Level III storm costs of $3 million, the Level III storm costs were $9 million, PGE shareholders would absorb $5 million. ($2 + $2 - $9 = -$5)

This latter scenario is essentially what happened in 2017. PGE's filing is seeking Commission approval to defer $8 million.[4/] PGE's Direct Testimony, Nicholson-Bekkedahl, page 3, lines 10-16, states that the 10-year average at the time for calendar year 2017 was $2 million. From PGE's testimony it appears that there were not any monies carried over to 2017. PGE states it incurred $10.6 million in 2017 Level III storm costs.[5/] After subtracting the $2 million 10-year average included in rates, and a total of

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4/ In response to AWEC Data Request 001, PGE states that its $9.4 million amount is not correct. See AWEC/102 at 1-2.

5/ PGE/100, Nicholson-Bekkedahl/4, line 2.

$10 million in costs incurred by the date of filing its deferral application, PGE still has a remaining $8 million it is seeking approval to defer in this UM 1817 filing.[6/]

Q. PLEASE PROVIDE SOME BACKGROUND ON THIS DOCKET.

A. PGE filed its application in this docket on January 11, 2017. Subsequently, PGE filed a rate case in 2018, docketed as UE 335, where the 2017 Level III storm costs were addressed. In that docket, and as argued in brief, PGE proposed that its accrual mechanism for Level III storm costs described above be revised to allow negative balances to be carried over to future years – that is, to create a balancing account rather than an accrual. The Commission order in that docket concluded the following:

> *We reject PGE's proposal, but we invite the company to return with an alternative that provides more justification, and a chain of causation justifying the change. Additionally, we commit to examine and resolve PGE's 2017 major storm deferral request and require that Staff bring that request before us within three months. We observe that Level III storm costs that can be justified as extreme may warrant a deferral under ORS 757.259(2)(e). We have held in the past that the magnitude of harm associated with an unforeseen event, or an event that cannot be effectively modelled, may justify an exercise of our discretion to authorize deferred accounting. Any request for an alternative Level III storm deferral mechanism based, in part, on claims of greater storm intensity due to climate change, however, should include some foundational analysis to justify this claim, and provide a chain of causation that connects evidence of expected increases in storm frequency and intensity to increased costs. There are implications in the record that the frequency and intensity of storms is being driven by climate change, yet this conclusion, while intuitively attractive, is not supported by evidence in the record for this case. While storm modeling is even more uncertain than the temperature modeling discussed above, we welcome a full discussion of both the modeling and the uncertainties around analysis specific to this region. As PGE works to refine and improve its proposals for major storm recovery, PGE should also work to ensure that there is balance in the mechanism that operates to encourage PGE to develop a robust and resilient*

[6/] PGE/100, Nicholson-Bekkedahl/1, line 11.

> *distribution system. Adapting to climate change should be a holistic undertaking in that recovery costs from more frequent high-impact events are balanced with investments and practices that mitigate the negative consequences from those events. If PGE's proposal will increase the ease of recovery of Level III storm costs for the company, PGE must explain and discuss the allocation of risks with customers and company incentives for developing a more resilient system that requires less expense to recover from Level III storms.*[7/]

Following this order, the Commission opened a contested case in this docket. PGE filed its Direct Testimony on March 27, 2019. On April 10, 2019, I received PGE's response to AWEC Data Request ("DR") 001, included in the attached Exhibit AWEC/102, where PGE noted a few errors. PGE filed revisions to its originally filed testimony on April 12, 2019. In its revised testimony, PGE is now requesting to defer $8 million, which is net of the $2 million it recovered in 2017 from its storm accrual mechanism, which I discuss below.

Q. DOES PGE'S TESTIMONY PROVIDE ADDITIONAL EVIDENCE ON WHETHER ITS 2017 LEVEL III STORM COSTS WERE DRIVEN BY CLIMATE CHANGE?

A. No. PGE chose not to address that broader issue in this docket. I did not see the word "climate" anywhere in the text of PGE's testimony of Nicholson-Bekkedahl. Indeed, PGE's response to AWEC DR 002 provides its Level III Storm costs for the past 20 years. Over this period, storm costs have been consistently sporadic with a few years in a row with no Level III Storms, followed by a few years in a row with Level III storms with no clear pattern or frequency. Additionally, while PGE did incur higher than average Level III storm costs in 2017, it incurred none in 2018. Thus, to the extent the

[7/] Docket No. UE 335, Order 18-464 at 14.

Commission wishes to examine the connection between storm costs and climate change, it should do so outside of this docket and limit its inquiry here to the appropriateness of PGE's request to defer $8 million in storm-related costs.

Q. DO YOU HAVE MUCH EXPERIENCE WITH THE COMMISSION'S TREATMENT OF DEFERRED ACCOUNTING PETITIONS?

A. Yes. In my 38 years employed with the Commission I reviewed or oversaw the disposition of dozens of deferred accounting petitions.

Q. IN YOUR EXTENSIVE EXPERIENCE, WHAT IS THE MOST IMPORTANT CONSIDERATION IN WHETHER THE COMMISSION GRANTS OR DENIES A DEFERRED ACCOUNTING PETITION?

A. Deferred accounting petitions are filed for different reasons. Sometimes it is because they are authorized under federal or state law or by a stipulation that the Commission has approved. Absent that circumstance, however, the most important consideration has traditionally been the financial impact to the utility. For example, deferrals that come to mind have been filed for poor hydroelectric conditions, extended power plant outages or changes in pension costs.

Q. DOES THE FINANCIAL IMPACT TO THE UTILITY DEPEND ON THE TYPE OF COST INVOLVED? IN OTHER WORDS, PGE IS REQUESTING RECOVERY OF STORM-RELATED COSTS. WOULD THE ANALYSIS BE DIFFERENT IF IT WERE SEEKING RECOVERY OF EMPLOYMENT-RELATED COSTS SUCH AS PENSIONS?

A. The Commission has made a distinction between costs that are the result of a "stochastic risk" and costs that are the result of a "scenario risk," which I will discuss in more detail below. Other than that distinction, however, the type of cost incurred has been, and should be, irrelevant. This is because rates are set on overall projected revenue requirements, keeping in mind that Oregon has a long tradition of using future test periods. When setting rates, it is generally understood that some forecasted costs will turn out to be higher than actual and some forecasted costs will be lower than actual. The purpose of setting rates is to provide the utility sufficient revenue *overall* to have the opportunity to earn its authorized rate of return. It is to the benefit of all parties that we look at the totality of rates because parties might not agree on individual issues within the case. Settlements often bundle issues together for that very reason—namely, parties can support the package on a revenue requirements or expense basis, while not agreeing to the specific level of each item. And again, with this in mind, it is certainly not expected that a specific cost turns out to be exactly as forecast.

Q. DOES THE COMMISSION'S ORDER IN UE 335 SUGGEST A DEVIATION FROM THIS PRECEDENT OF LOOKING TO THE FINANCIAL IMPACT OF THE UTILITY OVERALL?

A. Possibly. The Commission's statement that "Level III storm costs that can be justified as extreme may warrant a deferral" could be interpreted to mean that higher-than-normal storm costs may be eligible for deferred accounting, even if they do not significantly impact PGE financially overall. For the reasons discussed above, I recommend against the Commission changing its policy in this way, and continue to focus on the overall financial impact of the cost in question, and whether the cost is related to a stochastic or scenario risk.

Q. PLEASE DISCUSS HOW THE COMMISSION HAS CHARACTERIZED STOCHASTIC AND SCENARIO RISKS AND HOW IT HAS TREATED COSTS INCURRED FROM THESE RISKS.

A. Stochastic risks are risks that relate to typical business events or operations. The values or observations such as costs incurred in a year, or for an event, fall within a range of expected values.[8/] So, for example, if we are looking at an event, the question would be two-fold. Is the event to be reasonably expected to occur; and, if not, are the dollar impacts significant. Both factors would be considered. I think Dockets UM 1234 and UM 1623 are fairly instructive as examples delineating stochastic from scenario risks.

In UM 1234, the Commission defined stochastic and scenario risks. An excerpt from the Order 07-049 is provided below:

> *In Order No. 04-108, we explained that a stochastic risk can be predicted to occur as part of the normal course of events, whereas a scenario risk is not susceptible to prediction or quantification. In Order No. 05-1070, we further explained that we consider whether a deferral event was modeled in rates. If an event was modeled in rates, we evaluate whether the event was within a foreseen range of risk, or whether extenuating circumstances were involved that rendered the event unforeseeable. If the event was not modeled in rates, we assess whether it was otherwise foreseeable in the normal course of business.*[9/]

Additionally, also in UM 1234, Commission Staff provided an illustrative table to help distinguish between stochastic and scenario risks. The table below comes from Page 15 of the Owings-Galbraith Staff Reply Testimony in Docket UM 1234.

[8/] See Docket UM 1234, Staff/100, Owings-Galbraith/13, beginning at line 20.
[9/] Docket UM 1234, Order 07-049 at 9 (Feb. 12, 2007).

Table 3. Under What Circumstances Does the Commission Consider a Deferral?

Financial Effect	Type of Event		
	Stochastic Risk (1)(2)	Scenario Risk (3)(4)	Commission Approved (5)(6)
Substantial	Deferral Considered (7)	Deferral Considered	Deferral Considered
Material	Deferral Not Considered	Deferral Considered	Deferral Considered
Immaterial	Deferral Not Considered	Deferral Not Considered	Deferral Considered

(1) Stochastic risk is defined as a risk that can be predicted as part of the normal course of events; it is quantifiable and can be represented by a known statistical distribution (Order 04-108).

(2) Examples of stochastic risk are hydro variability, normal plant outages, employee compensation, and weather.

(3) Scenario risk is defined as a risk that is not susceptible to prediction and quantification; it is often represented by abrupt changes in business factors or practices (Order 04-108).

(4) Examples of scenario risk are catastrophic plant outages (Trojan), environmental costs, and material unexpected changes to costs.

(5) These events are either mandated, pursuant to Commission approval, or emerging from a rate case settlement.

(6) Examples of these events are DSM costs, a PGA, and intervenor funding.

(7) Event should be extraordinary.

So, a scenario risk can be a special variant of a stochastic risk if the event could not be reasonably expected. In the event we have a scenario risk, if the costs incurred are material, the Commission could consider granting a deferral. In the case of UM 1234, relating to a 105-day outage, the Commission found that it was not reasonably expected, the costs were material, and granted PGE's application to defer $26.439 million. Note that $26.439 million is over three times the amount PGE seeks to defer in this docket, and

PGE's deferral in UM 1234 was granted over ten years ago, when $26 million was worth more than it is today.

With regards to UM 1623, the Commission found that PGE's application to defer pension costs failed to meet the deferral statute requirement of minimizing rate changes or matching of costs and benefits. Further, the Commission found that even if it did meet the statutory test, as a stochastic risk, the financial impact of 86 basis points was not sufficient to warrant cost recovery. In that case, PGE sought recovery of $16.4 million, over twice what it requests in this docket.[10/]

Q. HOW DID PGE CATEGORIZE THE 2017 LEVEL III STORM COSTS?

A. PGE categorizes the 2017 Level III storm costs as scenario or paradigm risks. I should point out that in PGE's request for reconsideration of the UM 1071 Order, PGE stated that the hydro conditions for which it was seeking a deferral were not stochastic but were scenario or paradigm risks as well.[11/] The UM 1071 Order on reconsideration concluded that the hydro risk was stochastic.[12/]

Q. DO YOU AGREE WITH PGE THAT LEVEL III STORM COSTS ARE SCENARIO OR PARADIGM COSTS AND NOT STOCHASTIC?

A. I view the Level III storm costs as stochastic in nature. Stochastic risk means that there is a distribution of costs around some average. Sometimes costs are higher than normal. Sometimes costs are less than normal. That is the case here. PGE's response to AWEC DR 002 confirms this, as PGE has incurred at least some amount of Level III storm costs in 9 of the past 20 years, nearly every other year. The Level III storm costs are higher in

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10/ Docket UM 1623, Order No. 16-257 at 2 (July 7, 2016).
11/ Docket UM 1071, Order 04-357 at 6 (June 25, 2004).
12/ Id. at 10.

some years and lower in others. The set of various Level III storm costs across the years form a distribution. Not only that, but PGE collects a special accrual from customers based on the historical average of storm costs around which there is a stochastic distribution. I do not, therefore, see a fundamental distinction between the Level III storm costs and hydroelectric variability that would render Level III storm costs a scenario rather than stochastic risk.

Q. WHAT IS YOUR PERSPECTIVE ON WHY GRANTING DEFERRED ACCOUNTING APPLICATIONS SHOULD BE CAREFULLY CONSIDERED, ESPECIALLY WHEN DEALING WITH STOCHASTIC COSTS?

A. Having the opportunity for utilities to file for deferrals when costs are more than normal, especially when they are not financially significant, provides an unfair advantage to the utility. The utility knows its actual costs much better than interested parties. The utility will be able to file for recovery of higher-than-expected costs at a much higher frequency than other parties would be aware enough to file for deferrals to refund monies to customers. There could be one event that has significant negative financial impact that is offset by several smaller events of positive financial impacts.

In addition, providing utilities the opportunity to file deferrals for costs following a stochastic pattern reduces the incentive for utilities to manage costs. Even if events are outside of the utility's control, such as the weather, this does not mean the utility is powerless to manage the potential costs. For example, the utility can "harden" its facilities, timely manage vegetation through tree trimming, and underground facilities when it is sensible to do so.

Q. HAS THE COMMISSION EVER IDENTIFIED A BRIGHT LINE AMOUNT FOR DETERMINING WHETHER A COST IS ELIGIBLE FOR DEFERRED ACCOUNTING?

A. No, the Commission has (appropriately, in my mind) maintained its discretion in determining whether a cost is high enough to meet the "substantial" or "significant" thresholds for stochastic and scenario risks, respectively. It has, however, provided guidance that can be used in this case. As noted above, the Commission has granted deferrals of costs associated with scenario risks of $26 million in 2007, but has denied deferrals of costs associated with stochastic risks of $31.6 million in 2004 and $16.4 million in 2016.[13/] In this latter example, the Commission stated, on page 4 of Order 16-257, that the impact in 2013 (the year most of the costs subject to PGE's deferral were incurred) was 86 basis points, "well within the bounds of acceptable risks between rate cases." Furthermore, on page 19 of Order 07-049, it appears to me that the Commission set a materiality threshold of 100 basis points. I provide the text of the relevant section on the order below.

> *For the Boardman Outage, we find the appropriate measure of normal risk to be the range of forseeability we earlier defined as a reasonable deviation range around the pertinent forced outage rate. We find that PGE should not be allowed to defer costs that would likely be associated with an outage within this range of normal risk. However, as parties did not present evidence in this proceeding that would allow us to explicitly calculate this level of costs, we find it appropriate to approximate the financial impact of this range of risk. We determine that a 100 basis point deadband on ROE should be applied to costs eligible for deferral.*

[13/] Docket No. UM 1071, Order No. 04-108 at 9 (Mar. 2, 2004); Order No. 16-257 at 2.

Q. BASED ON COMMISSION PRECEDENT, ARE PGE'S 2017 LEVEL III STORM COSTS ELIGIBLE FOR DEFERRED ACCOUNTING EVEN IF THE COMMISSION AGREES WITH PGE THAT STORM COSTS REPRESENT A SCENARIO RISK?

A. No. Regardless of whether storm costs are considered to be a "stochastic" or "scenario" risk, $8 million is not a significant enough financial impact to warrant a deferral under any circumstances. In Response to AWEC DR 007, Attachment A, as well as the discussion on lines 6 and 9 of Page 14 of the revised Direct Testimony of Nicholson-Bekkedahl, the ROE impact of the 2017 Level III storm costs was 36 basis points.[14/] Because 36 basis points is far less than the Order 07-049 materiality threshold of 100 basis points for scenario events, the PGE deferral application should be denied, regardless of whether the Commission determines 2017 Level III storm costs to be a stochastic or scenario event. In fact, PGE has never incurred storm costs in the past 20 years that are significant enough to warrant a deferral.

Q. DOES THIS INDICATE A FLAW IN COMMISSION PRECEDENT ON DEFERRALS?

A. No, it simply shows that some categories of costs are not large enough in the context of PGE's overall revenue requirement to be eligible for deferrals. That is, in fact, my understanding of why PGE has a special cost recovery mechanism for storm costs today. That mechanism is designed to insulate PGE from some amount of risk associated with Level III storms that would not otherwise be eligible for deferred accounting.

14/ See AWEC/102 at 7-8.

Q. DOES PGE'S STORM ACCRUAL MECHANISM MAKE IT MORE OR LESS APPROPRIATE TO AUTHORIZE DEFERRED ACCOUNTING FOR ITS 2017 LEVEL III STORM COSTS?

A. It makes it less appropriate because PGE already has a mechanism that reduces its risk related to these storm costs and provides it with a level of recovery that balances customer and utility risk and does not disincentivize PGE from investing in distribution system resiliency.

Additionally, in the UM 1234 Order, the Commission made it clear that events that do qualify for deferred accounting should not be included in any multi-year average ratemaking mechanism. Meaning that the 105-day Boardman plant outage should not be used to determine the moving average forced outage rate. Given that the 2017 Level III storm costs were included in calculating the 10-year average for the accrual mechanism, it would be inconsistent to also grant a deferral for the 2017 Level III storm costs. I assume the UE 335 Order, while it included the 2017 Level III storm costs in the 10-year moving average for rates purposes, was not expressly changing the Commission's reasoning in the UM 1234 Order.

Q. WHAT ABOUT THE OTHER PGE POINT THAT THE DEFERRAL WILL APPROPRIATELY MATCH THE COSTS BORNE AND THE BENEFITS RECEIVED BY CUSTOMERS?

A. I do not believe this objective is met either. I do not see in the application or testimony where PGE states any analysis or proposal to have the rates charged to those customers that had storm electric outages and benefited by having service restored. Rather, presumably the rates would be charged to all customers with the likely spread consistent with distribution services revenue requirement given that it is damage primarily or solely to distribution customers. Furthermore, PGE failed to provide any information on the likelihood that the customers experiencing the outage in 2017 are still PGE customers. If PGE was authorized to defer, and collect the costs in rates, PGE would charge new customers costs associated with the 2017 costs. Those new customers did not benefit from the system restoration and yet are being charged for the costs.

Q. DO YOU BELIEVE THAT PGE HAS MORE INCENTIVE TO "HARDEN" SERVICE EQUIPMENT IF PGE HAS EXPOSURE TO LEVEL III STORM COSTS?

A. Yes. To the extent the Company has exposure to costs, it is reasonable to conclude that it will take actions to mitigate those costs from occurring. This includes taking the actions noted in the PGE testimony, which it is taking under the current regulatory construct in which it bears some risk for storm-related costs. PGE does not testify that it would make the same investments if this risk were eliminated or significantly mitigated.

Q. IF THE COMMISSION FOUND THAT A DEFERRAL SHOULD BE AUTHORIZED, DOES THAT MEAN THAT THE PGE-REQUESTED FULL $8 MILLION SHOULD BE DEFERRED?

A. No. Part of PGE's argument is that the 2017 Level III storm costs are extraordinary and as such should be deferrable for later recovery. However, I do not agree with PGE's analysis as to the amount that should be deferred. To get to the revised request of $8 million, PGE took the revised deferral request base of $10 million, and subtracted the amount recovered in rates of $2 million to yield the $8 million value.

Q. WHAT IS YOUR DISAGREEMENT WITH THIS CALCULATION AS IT SEEMS FAIRLY STRAIGHT-FORWARD.

A. The issue I have with the calculation is the notion that you defer the full difference from the average – the $8 million. What should be deferred should be the amount that is extreme. Any amount that is not extreme should be excluded from the deferral. For example, let us assume that the 2017 Level III storm damage cost was $5 million. Would PGE have asked for deferral and rate recovery, and received approval from the Commission? I think not. If PGE should not, from a deferral perspective, get cost recovery for the first $3 million above the ten-year average of $2 million, why should PGE recover the first $3 million above the $2 million average when Level III Storm costs are $10 million? PGE's request creates a perverse incentive where higher storm damage costs gets PGE 100 percent recovery while lower storm damage costs results in no recovery. This would actually incentivize PGE to incur greater costs in responding to a Level III storm whenever costs are approaching the triggering level where the Commission is supportive of a deferral application.

Q. IS THE LOGIC OF ESSENTIALLY A DEAD-BAND AROUND AN AVERAGE SUPPORTED BY ANY OPUC ORDER?

A. Yes. As discussed earlier, Order 07-049, in Docket UM 1234, concerns a Boardman outage. The Commission supported the deferral application because the Boardman outage could not reasonably be predicted and therefore classified the event as a scenario risk. In deciding how much of the deferral application to grant, the Commission decided that the amount of risk the utility normally would absorb should be excluded from the request. The text from that order is presented below:

> *If an event is deemed a scenario risk because it is outside a range of normal risk, we find that it is appropriate to apply a measure of normal risk when allocating, for deferral purposes, the costs associated with the event. We recognize, however, that the proposed 250 basis points deadband on ROE may not be the appropriate measure of normal risk to be applied in such a case. Rather, we find that the measure of normal risk applied to a scenario event should be contextual, reflecting the pertinent range of risk, and considering whether the scenario event is isolated, or combined with another scenario event or other extenuating circumstances.*
>
> *For the Boardman Outage, we find the appropriate measure of normal risk to be the range of forseeability we earlier defined as a reasonable deviation range around the pertinent forced outage rate. We find that PGE should not be allowed to defer costs that would likely be associated with an outage within this range of normal risk. However, as parties did not present evidence in this proceeding that would allow us to explicitly calculate this level of costs, we find it appropriate to approximate the financial impact of this range of risk. We determine that a 100 basis point deadband on ROE should be applied to costs eligible for deferral.*[15/]

It is clear from this order that in UM 1817, PGE should not be allowed to defer the full $8 million as some level of the amounts above the 10-year average amount of $2 million is normal risk and variation and so should not be included in the deferral amounts.

Q. IF THE COMMISSION DETERMINES TO COMPARE THE MAGNITUDE OF 2017 LEVEL III STORM COSTS WITH PREVIOUS YEARS' STORM COSTS TO DETERMINE A DEFERRAL THRESHOLD, HOW SHOULD THE COMMISSION DEVELOP THAT THRESHOLD?

A. It should be based on the standard deviation from average Level III storm costs. It is a generally accepted principle in statistics that data points that fall more than two standard deviations away from the mean would not be expected – they are considered outliers, or in the Commission's language from UE 335, "extreme." Thus, if the Commission is to

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[15/] Order 07-049 at 19.

consider granting a deferral based on a comparison of 2017 Level II storm costs with average Level III storm costs, it should only allow recovery of costs that fall outside of two standard deviations from the mean.

Q. WHAT IS THE STANDARD DEVIATION OF LEVEL III STORM COSTS?

A. The standard deviation in PGE-provided Level III storm cost history is $3.2 million, and the amount that represents two standard deviations from the average storm cost is $8.6 million. For this application, I analyzed the Level III storm history, in constant dollars, to see what the standard deviation was in Level III storm costs. PGE provided this information in response to AWEC DR 002. A copy of PGE's response to the relevant portions of AWEC DR 002 is attached as AWEC/102, Hellman/3-5.

Q. WHAT DOES THAT IMPLY FOR THIS DEFERRAL APPLICATION?

A. If the Commission were to grant the application, then the 2017 Level III storm costs overall, at $10.6 million, do fall outside of two standard deviations and could be considered an outlier. This would indicate that PGE could defer $2 million, as this represents the amount above the $8.6 million "dead band" that represents two standard deviations from the mean. However, because only $10 million of these costs is subject to PGE's application, and it has already recovered $2 million of these costs through its storm accrual mechanism, PGE is only seeking recovery of $8 million.

For clarity, I wish to reiterate that I believe the Commission should look primarily to the financial impact on the utility overall and not to the magnitude of storm costs in particular. However, even if the Commission were to measure the impact of PGE's 2017 Level III storm costs relative to prior years' Level III storm costs in determining whether to grant a deferral, my analysis above shows that a deferral is unwarranted here even by this measure, as PGE seeks recovery of costs that represent less than two standard deviations from the average amount of Level III storm costs.

Q. SHOULD THE NUMBER OF DEFERRALS PGE HAS OUTSTANDING BEFORE THE COMMISSION IMPACT ITS DECISION IN THIS DOCKET?

A. In my opinion, this is a clear-cut case where no deferral is warranted. However, to the extent the Commission is "on the fence" about whether a deferral is warranted here, the number of other deferrals PGE has filed in recent years should further influence the Commission to deny this one. PGE notes 17 different open deferrals in its testimony and response to AWEC DR 10.[16/] A few of these, like for intervenor funding or power costs for qualifying facilities, are explicitly authorized by Oregon law or an approved stipulation. For most, however, PGE appears to have inferred this type of authorization without it being expressly granted. For instance, PGE cites the Commission's order acknowledging its 2016 integrated resource plan as the authority to defer costs associated with its demand response testbed pilot.[17/] That order, of course, simply acknowledged PGE's action plan to acquire a certain amount of demand response and did not say anything about authorizing deferred accounting for the associated costs.[18/] Similarly, PGE cites SB 1547 for authority to defer community solar start-up costs and electric

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16/ AWEC/102 at 8-9 (PGE Resp. to AWEC DR 10, Attach. A).
17/ Id.
18/ Docket No. LC 66, Order No. 17-386 at 9 (Oct. 9, 2017).

vehicle pilot program costs.[19] That law, however, only authorizes recovery of costs from customers, but says nothing about deferred accounting.[20] This is in notable contrast to ORS 757.072(4), which requires the Commission to "allow a public utility to defer inclusion of [financial assistance] amounts in rates as provided in ORS 757.259." PGE can recover costs by filing a rate case, so a statute authorizing recovery does not, by itself, authorize a deferral. By interpreting these and similar orders and statutes in this way, PGE proposes to eliminate its risk with as many categories of costs as possible. This makes it all the more important that PGE bear normal risks of utility operation, like those associated with storms.

Q. DO YOU HAVE ANY REMAINING ISSUES TO DISCUSS?

A. Yes. PGE is over-recovering the Level III storm cost amount included in rates as established in UE 335. Currently, rates have a value of $3.8 million.[21] This $3.8 million value calculation is shown in UE 335, PGE/801, Nicholson-Bekkedahl/1.[22]

PGE provided an updated PGE 2017 Level III storm damage cost of $10.6, which when escalated by inflation yields a value of $11.1 million. This is lower than the PGE UE 335 Exhibit 801 similar value of $11.9 million. The ten-year average Level III storm costs changes when the 2017 value changes.

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[19] AWEC/102 at 8-9 (PGE Resp. to AWEC DR 10, Attach. A).
[20] ORS 757.386(7)(c); 757.357(5).
[21] PGE/100 at 3, fn. 3.
[22] See AWEC/103 at 1.

Q. WHAT IS THE 10-YEAR AVERAGE USING PGE'S UPDATED VALUES?

A. The updated value is $3.7 million. That means rates are over-collecting $100,000 on an annual basis. I recommend the Commission direct PGE to return the over-collected amounts with interest.

Q. IN THE EVENT THE COMMISION AUTHORIZES THE DEFERRAL, WOULD THAT IMPACT THE 10-YEAR AVERAGE LEVEL III STORM DAMAGE COST AS ADOPTED IN UE 335?

A. Yes. As noted earlier, the order in UM 1234, Order 07-049, infers that if an event qualifies as appropriate for deferral, then that event should be removed from other related mechanisms, such as the average forced outage rate, so as to not allow for double recovery. This means that if the Commission were to approve the deferral application, the 2017 Level III storm costs needs to be removed, or revised, from the ten-year moving average of Level III storm costs.

Q. HAVE YOU DONE THAT CALCULATION?

A. Yes. Assuming the 2017 Level III storm cost is zero for purposes of calculating the 10-year moving average, the new 10-year Level III Storm cost average is $2.6 million.[23/] Given that UE 335 rates have a value of $3.8 million included in rates, PGE should accrue with interest and return to customers the overcharges that amount to $1.2 million annually.

Q. DO YOU HAVE ANY FINAL REMARKS?

A. Yes. I appreciate PGE's forthrightness in both investigating and identifying its error in total 2017 Level III storm damage costs. PGE could have chosen not to investigate this

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[23/] I should note that assuming 2017 Level III storm costs equal to zero is reasonable given the fact that in many of the past years, Level III storm costs are zero, and were zero in 2018.

matter thoroughly. PGE should be commended for being diligent and forthright in including the correction in its responses to AWEC data requests.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1817

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
Application for the Deferral of Storm-Related Restoration Costs.	)
	)
	)

EXHIBIT AWEC/101

QUALIFICATION STATEMENT OF DR. MARC M. HELLMAN

Marc Hellman, PhD.

Witness on Behalf of Alliance of Western Energy Consumers

2760 Eagle Eye Ave NW

Salem, Oregon 97304

WORK EXPERIENCE

Dr. Hellman, of MH Energy Economics LLC, has nearly 40 years' experience in the field of regulatory economics and has consulted for telecommunications and electric industries as well as Boeing Computer Services. Beginning in 1979, Dr. Hellman was employed by the Public Utility Commission of Oregon (OPUC) in various capacities and has specialized in cost-based pricing and revenue requirements analysis for electric, natural gas, telecommunications and water industries. Up to September 2017, Dr. Hellman was Administrator of the Energy Rates, Finance and Audit Division and managed over a dozen expert staff of economists, accountants, and financial analysts dedicated to conducting a wide range of research on such matters including: utility cost of capital, utility financing applications, rate spread and rate design, utility merger and acquisitions, as well as conducting utility audits and benchmarking studies. In 2013, Dr. Hellman was appointed to advise the Oregon Governor's Office on the Columbia River Treaty review. Dr. Hellman received his PhD in Economics from Claremont Graduate School in 1983, and from 2008 through September 2016, was an instructor at Oregon State University teaching micro and macroeconomics as well as energy economics. Dr. Hellman has also recently provided consulting services for the Commonwealth Utilities Corporation with headquarters in Saipan, the Smart Energy Alliance in a Nevada Power general rate filing before the Nevada Commission, and the South Dakota Intrastate Pipeline Company.

Major Regulatory Studies and Reports

Public Utility Commission of Oregon, – chaired the water industry stakeholder workgroup and led discussions reviewing in total, both in scope of regulation and funding, the Commission Water Regulation Program, with the production of the report titled, "Review of the Oregon Public Utility Commission's Water Program," August 2002.

Public Utility Commission of Oregon, – authored major electric industry restructuring testimony presented before the Oregon Legislature, July 1997.

Public Utility Commission of Oregon, – led and directed Commission staff in reviews of several utility mergers and acquisitions including ScottishPower acquisition of PacifiCorp and Mid American holdings acquisition of PacifiCorp.

Public Utility Commission of Oregon, – led the first known study establishing estimates of unbundled network elements, memorialized in the report titled, "Telecommunications Building Blocks, Cost Report," July 1993.

Public Utility Commission of Oregon, – designed policies to address ratemaking treatment for research and development activities by Advanced Technologies, a fully owned subsidiary of US West, "Alternative Regulatory Policies for Telecommunications Utilities' Research and Development Costs," May 1992.

Public Utility Commission of Oregon, – analyzed and scored many alternative ratemaking mechanisms geared to incent electric utilities to acquire cost-effective conservation, "Investigation into Electric Utility Incentives for Acquisition of Conservation Resources," August 1991.

Public Utility Commission of Oregon, – as a precursor to integrated least cost planning, authored the report titled, "The 1989 Update to a Report on the PGE and PP&L Energy Surplus: Its Size, Duration, and Management," September 1988, as well as, "A Report on the PGE and PP&L Energy Surplus: Its Size, Duration, and Management," September 1989.

Expert Witness Testimony

Public Utility Commission of Oregon (Bonneville Power Administration Docket REP-12), – select panel testimony in support of a $2 billion settlement of statutory rights to low-cost federal power. 2011

Public Utility Commission of Oregon (Bonneville Power Administration Docket WP-10), – analysis of statutory test that limits access to low-cost federal power by residential and small-farm customers of investor-owned utilities. 2009

Public Utility Commission of Oregon (Bonneville Power Administration Docket WP-07S), – analysis of rights to low-cost federal power by residential and small-farm customers of investor-owned utilities. 2008

Public Utility Commission of Oregon (Docket UM 1050), – analysis of interjurisdictional cost allocation methods applicable to PacifiCorp. Docket was culmination of multi-year collaborative effort among the states of Washington, Idaho, Wyoming, Utah and Oregon to reach an agreed to allocations method. 2004

Public Utility Commission of Oregon (Docket UE 88), – analysis of alternative decoupling mechanisms designed to break the link between utility kWh sales and utility profits applicable to PacifiCorp. 1994

Public Utility Commission of Oregon (Docket UE 79), – ratemaking analysis of Portland General Electric wholesale power sales relating to the WNP #3 Settlement. 1990

Public Utility Commission of Oregon (Bonneville Power Administration Docket WP-87), – analysis of rights to low-cost federal power by residential and small-farm customers of investor-owned utilities. 1987

Public Utility Commission of Oregon (Federal Energy Regulatory Commission Docket ER 82-2011-003), – economics of nonfirm energy production in the Pacific Northwest and pricing of such power. 1984

Public Utility Commission of Oregon (Bonneville Power Administration Docket WP-83), – analysis of rights to low-cost federal power by residential and small-farm customers of investor-owned utilities, value of Direct Service Industry reserves, estimates of the Pacific Northwest Region long run incremental cost of wholesale power.

<u>Telecommunications</u>

- *Public Utility Commission of Oregon* – "The Status of Competition and Regulation in the Telecommunications Industry," – separate studies published roughly each year beginning in 2001.
- *Public Utility Commission of Oregon (Docket UM 351, Phase II),* – general pricing and unbundling policies for telecommunications retail services and unbundled network elements – 1995.
- *Public Utility Commission of Oregon (Docket UM 351),* – generic investigation to develop long run incremental cost of unbundled network elements – 1993.
- *Public Utility Commission of Oregon (UM 295),* – ratemaking policies for telecommunications research and development activities – 1992.
- *Public Utility Commission of Oregon (UT 80),* – alternative form of regulation review and proposal for US West – 1991.
- *Public Utility Commission of Oregon (US WEST Docket UT 85),* – broad pricing policy – 1989.
- *Public Utility Commission of Oregon (PNB Docket UF 3565),* – telecommunications pricing issues, review of price elasticity studies, Western Electric Adjustment – 1980.

EDUCATION

CLAREMONT GRADUATE SCHOOL, CLAREMONT, CALIFORNIA – MA, 1980, PhD, 1983

- Specialization in Optimization Theory/Microeconomic Theory/Monetary Economics.

CALIFORNIA STATE POLYTECHNIC UNIVERSITY OF POMONA -- BS, 1977

- Major in Mathematics and Economics.

OTHER

- Graduate of 1997 Leadership Oregon Program. Each year, from all state employees, 20 to 30 future government leaders are selected to participate in LOP to learn about other state agencies and benefit from executive training.
- Member, American Economic Association
- Economics at Oregon State University

PUBLICATIONS

The Economics of a Surplus in Electrical Generating Capability: The Pacific Northwest," - Public Utilities Fortnightly, January 5, 1984, pages 45-47.

Load Curve Responsiveness to Weather and the Cost Effectiveness of Conservation," - Public Utilities Fortnightly, September 30, 1982, page 51.

FORMAL TESTIMONY OFFERED IN THE FOLLOWING PROCEEDINGS:

Cause	Agency	Year	Company	Topics
R-48	OPUC	1980	Generic-Electric	Conservation potential from electric rate design
UF 3565	OPUC	1980	PNB	Telecommunication pricing issues, review of elasticity studies, Western Electric Adjustment
UF 3753	OPUC	1982	CPN	LRIC methodology, electric rate spread and rate design
UF 3779	OPUC	1982	PP&L	LRIC and electric rate spread, and rate design
UF 3900	OPUC	1983	PP&L	LRIC and electric rate spread, and rate design
WP 83	BPA	1983	BPA	LRIC methodology and value of DSI energy and capacity reserves
AR 112	OPUC	1984	Generic-Electric	Electric LRIC methodology and rate spread and rate design policy
ER 82-2011-003	FERC	1984	BPA	Economics of nonfirm electric energy sales to the Pacific Southwest
UE 44	OPUC	1985	Generic-Electric	Electric rate spread and rate design, LRIC methodology
UE 47/48	OPUC	1986	PGE	Electric rate spread and rate design, valuation of WNP #3 settlement agreement
VI-86-OP-01	BPA	1986	BPA	Review of BPA proposed Variable Industrial Power Rate
UE 58	OPUC	1987	PP&L	Electric rate spread and rate design
UE 70	OPUC	1987	PP&L	LRIC methodology and electric rate spread and rate design
WP 87	BPA	1987	BPA	7(b)(2) rate test
UT 85	OPUC	1989	USWC	Telecommunications rate design policies

Cause	Agency	Year	Company	Topics
UT 80	OPUC	1991	USWC	Telecommunications alternative form of regulation summary witness and productivity estimation
UM 295	OPUC	1992	Generic-Telecommunications	Ratemaking policy for telecommunications research and development activities
UE 88	OPUC	1994	PGE	Decoupling mechanism design to break link between kWh sales and utility profits
UM 351, Phase II	OPUC	1995	Generic-Telecommunications	General pricing and unbundling policies of telecommunications functionalities
UM 1050	OPUC	2004	PacifiCorp	Interjurisdictional cost allocation methods
WP-07S	OPUC	2008	BPA	7(b)(2) rate test, retroactive ratemaking
WP-10	OPUC	2009	BPA	7(b)(2) rate test
REP-12	OPUC	2011	BPA	Long-term residential exchange settlement
Docket No. 17-06003 and 17-06004	Nevada PUC	2017	Smart Energy Alliance	Residential net metering rates and rate design for direct access customers
Docket No. NG17-009	South Dakota PUC	2017	South Dakota Intrastate Pipeline Company	Rate of Return, Decommissioning policy, and management fee
Docket No. U-170970	WUTC	2017	Avista	Review of Proposed Hydro One Acquisition of Avista
Docket UE 319	OPUC	2017	Portland General Electric	FTEs, Wages, Pensions, R&D expense

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1817

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
Application for the Deferral of Storm-Related Restoration Costs.	)
	)
	)

EXHIBIT AWEC/102

COMPANY RESPONSES TO AWEC DATA REQUESTS

April 10, 2018

TO: Jesse O. Gorsuch
Davison Van Cleve, PC

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1817
PGE Response to AWEC Data Request No. 001
Dated April 1, 2019

Request:

Please identify each account in which PGE's storm expenses proposed to be deferred in this docket were booked, including amounts booked to each account. For each account, describe the account and types of costs recorded in those accounts.

Response:

Attachment 001-A provides the requested information, which has updated costs related to the 2017 storm deferral. PGE had inadvertently included storm costs in its testimony that were incurred prior to the January 11, 2017 filing date.

UM 1817 PGE Response to AWEC DR 001
Attachment 001-A

2017 Level III Expenses by FERC Accounts

* Income Statement accounts only
* exclude ST Labor

FERC Account	Description	1000006735 01.11.2017 Big Five Snow Storm	1000006819 04.07.2017 Wind Storm	1000007051 10.21.2017 Wind Storm	Total
561.2	Transmission Maintenance - Load dispatch: Monitor and operate transmission system	$ 729			$ 729
563	Transmission Maintenance - Overhead line expense (Major only)	$ 66			$ 66
569.2	Transmission Maintenance - Maintenance of computer software				$ -
573	Transmission Maintenance - Maintenance of miscellaneous transmission plant				$ -
580	Distribution Operations - Operations supervision and engineering	$ 89,254	$ 111,064	$ 23,873	$ 224,192
581	Distribution Operations - Line and station expenses (non major only)	$ 1,017	$ 6,413	$ 1,292	$ 8,723
582	Distribution Operations - Station expenses (major only)	$ 4,207	$ 12,798		$ 17,004
583	Distribution Operations - Overhead line expenses (major only)	$ 1,905	$ 44		$ 1,949
586	Distribution Operations - Meter expenses	$ 1,001			$ 1,001
587	Distribution Operations - Customer installation expenses	$ 56		$ 1,024	$ 1,080
588	Distribution Operations - Miscellaneous distribution expenses	$ 23,856	$ 7,650		$ 31,506
590	Distribution Maintenance - Maintenance supervision and engineering (major only)	$ 7,403	$ 7,798	$ 44	$ 15,246
591	Distribution Maintenance - Maintenance of structures (major only)	$ 174	$ 1,553		$ 1,727
592	Distribution Maintenance - Maintenance of station equipment (major only)	$ 28,648	$ 18,137		$ 46,786
592.2	Distribution Maintenance - Maintenance of Energy Storage Equipment	$ 1,101			$ 1,101
593	Distribution Maintenance - Distribution Maintenance	$ 3,589,077	$ 4,499,416	$ 478,708	$ 8,567,201
594	Distribution Maintenance - Maintenance of underground lines (Major only)	$ 87,883	$ 66	$ 18,210	$ 106,159
595	Distribution Maintenance - Maintenance of line transformers	$ 2,032	$ 1,141	$ 3,659	$ 6,832
596	Distribution Maintenance - Maintenance of street lighting and signal systems	$ 2,589	$ 44		$ 2,633
598	Distribution Maintenance - Maintenance of miscellaneous distribution plant		$ 839		$ 839
903	Customer Account Expenses (Operations) - Customer records and collection expenses	$ 2,702	$ 3,779		$ 6,481
905	Customer Account Expenses (Operations) - Miscellaneous customer accounts expenses (Major only)	$ 25,227	$ 61,977	$ 4,947	$ 92,151
908	Customer Service and Informational Expenses - Customer assistance epense (Major only)		$ 1,666		$ 1,666
920	Administrative and General Expenses (Operation) - Admistrative and general salaries	$ 222,308	$ 18,308		$ 240,616
921	Administrative and General Expenses (Operation) - Office supplies and expenses	$ 4,221	$ 55		$ 4,275
925	Administrative and General Expenses (Operation) - Injuries and damages	$ 5,330			$ 5,330
935	Maintenance - Maintenance of general plant	$ 751	$ 2,268		$ 3,019
Incurred Costs		**$ 4,101,539**	**$ 4,755,014**	**$ 531,757**	**$ 9,388,311**
Labor Loadings associated with OT & Prem. Pay		$ 256,062	$ 296,723	$ 58,129	$ 610,914
Transportation Overheads assoc. w/ OT & Prem. Pay		$ 25,054	$ 23,660	$ 4,309	$ 53,023
Incremental Loadings		**$ 281,117**	**$ 320,383**	**$ 62,438**	**$ 663,937**
Total Recoverable Cost		**$ 4,382,655**	**$ 5,075,397**	**$ 594,195**	**$ 10,052,248**

April 10, 2018

TO: Jesse O. Gorsuch
Davison Van Cleve, PC

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1817
PGE Response to AWEC Data Request No. 002
Dated April 1, 2019

Request:

Please provide:

a. **PGE's Level III storm costs in nominal dollars for each of the past 20 years. If costs for 2018 are not yet available, please identify when they will be available;**

b. **PGE's Level III storm costs in constant dollars for each of the past 20years; and**

c. **PGE's Level III storm costs in terms of $ per kWh for each of the past 20 years, where kWh are the retail kWh sales for that respective year.**

Response:

a. Attachment 002-A provides the requested information. Storm costs do not include straight time labor or associated labor loadings.

b. Attachment 002-B provides the requested information.

c. Attachment 002-C provides the requested information.

UM 1817 PGE Response to AWEC DR 002
Attachment 002-A
Page 1

PGE Major Storms, 1999-2018	
Year	**Nominal Costs**
1999	$ -
2000	$ -
2001	$ -
2002	$ -
2003	$ -
2004	$ 2,976,869
2005	$ -
2006	$ 3,869,486
2007 [1]	$ 886,621
2008	$ 5,936,058
2009 [2]	$ 2,106,514
2010	$ -
2011	$ -
2012	$ -
2013	$ -
2014	$ 5,623,875
2015	$ 5,161,513
2016	$ 4,504,081
2017	$ 10,557,354
2018	$ -

Notes:
(1): The 2007 Level III storm expense is related to the December 2006 windstorm.
(2): The 2009 Level III storm expense is related to the December 2008 snow storm.

Summary of Costs Attributable to Level III Storms

Year	Level III Storm Costs	Inflation[3]	$2019 Storm Costs
1999	-	2.21%	-
2000	-	3.36%	-
2001	-	2.85%	-
2002	-	1.58%	-
2003	-	2.28%	-
2004	2,976,869	2.66%	3,984,721
2005	-	3.39%	-
2006	3,869,486	3.23%	4,853,253
2007 [1]	886,621	2.83%	1,081,456
2008	5,936,058	3.86%	6,971,468
2009 [2]	2,106,514	-0.37%	2,483,174
2010	-	1.68%	-
2011	-	3.12%	-
2012	-	2.09%	-
2013	-	1.48%	-
2014	5,623,875	1.59%	6,007,691
2015	5,161,601	0.13%	5,506,888
2016	4,504,081	1.27%	4,745,316
2017	10,557,354	2.13%	10,891,355
2018	-	2.45%	-
2019	-	0.70%	-

Notes:
[1]: The 2007 Level III storm expense is related to the December 2006 windstorm.
[2]: The 2009 Level III storm expense is related to the December 2008 snow storm.
[3]: Source: *United States Consumer Price Index for All Urban Consumers (1970 - 2019)* - http://www.dlt.ri.gov/lmi/pdf/cpi.pdf

April 10, 2018

TO: Jesse O. Gorsuch
Davison Van Cleve, PC

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1817
PGE Response to AWEC Data Request No. 007
Dated April 1, 2019

Request:

Please provide an estimate of the basis point reduction in ROE for each of the years that the Level III Storm Accrual Mechanism has been in place for any Level III Storm costs not recovered in rates. Please provide all workpapers.

Response:

Attachment 007-A provides the requested information. The following describes the calculations for each basis point reduction:

"Storm Cost" tab lists, by year, amounts collected for storm restoration (column B), actual storm restoration costs (column C), and balances (column D) representing: 1) accumulated reserves where storm restoration costs were less than the accumulated reserve (2011-2014); and 2) amounts not recovered where storm restoration costs were greater than the accumulated reserve (2015-2017).

"2015 ROO", "2016 ROO", and "2017 ROO" tabs show PGE's summary Results of Operation Reports (ROOs) as filed by May 1, and submitted as PGE Exhibit 102 with each year's Power Cost Adjustment Mechanism filing by July 1.

"2015 ROO Adj", "2016 ROO Adj", and "2017 ROO Adj" tabs show the impact of adding revenue equal to the unrecovered storm restoration costs to cell H16 in each ROO. Column L shows: 1) the delta revenue equal to the recovery (row 16); and 2) the basis point difference from that delta revenue (row 37) on PGE's return on equity (ROE).

For 2011 through 2014, where storm restoration costs were less than the accumulated reserve, the balance only carried forward and did not provide any positive impact to PGE's ROE.

UM 1817 PGE Response to AWEC DR No. 007
Attachment 007-A
Page 1

PORTLAND GENERAL ELECTRIC
OPUC REGULATORY REPORTING
RESULTS OF OPERATIONS
January 1, 2017 - December 31, 2017
(Thousands of Dollars)

Regulatory adjustments based on **Docket UE 294, Order 15-356**	Actual Utility Results	Type I Accounting Adjustments	Regulated Utility Actuals	Type I Adjustments	Regulated Adjusted Results	Type II Adjustments	Pro Forma Results	Delta (5)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
Operating Revenues								
Sales to Consumers	1,858,861	(131)	1,858,730	(3,560)	1,863,727	7,392	1,871,119	8,557
Sales for Resale	116,335	(116,335)	0	0	0	0	0	
Other Operating Revenues	41,241	(15,554)	25,687	0	25,687	0	25,687	
Total Operating Revenues	2,016,437	(132,021)	1,884,417	(3,560)	1,889,414	7,392	1,896,806	
Operation & Maintenance								
Net Variable Power Cost	601,778	(127,158)	474,621	0	474,621	(13,169)	461,452	
Total Fixed O&M	304,629	(3,326)	301,302	0	301,302	3,625	304,928	
Other O&M	262,416	957	263,373	(16,733)	246,640	2,334	248,973	
Total Operation & Maintenance	1,168,823	(129,527)	1,039,296	(16,733)	1,022,563	(7,210)	1,015,353	
Depreciation & Amortization	342,742	0	342,742	(4,556)	338,186	1,830	340,016	
Other Taxes / Franchise Fee	122,375	(745)	121,630	(91)	121,539	1,157	122,696	
Income Taxes	85,026	(1,943)	83,083	8,343	91,426	5,630	97,056	
Total Oper. Expenses & Taxes	1,718,966	(132,216)	1,586,751	(13,037)	1,573,714	1,406	1,575,120	
Utility Operating Income	297,471	195	297,666	9,476	315,700	5,986	321,686	
Rate of Return	6.27%		6.27%		6.83%		7.11%	0.19%
Return on Equity	7.17%		7.17%		8.26%		8.64%	0.36%

ROE based on actual capital structure.

	Actual Utility Results	Type I Accounting Adjustments	Regulated Utility Actuals	Type I Adjustments	Regulated Adjusted Results	Type II Adjustments	Pro Forma Results
Average Rate Base							
Utility Plant in Service	9,845,463	0	9,845,463	(123,295)	9,722,168	146,314	9,868,481
Accumulated Depreciation	4,532,983	0	4,532,983	0	4,532,983	226,954	4,759,937
Accumulated Def. Income Taxes	645,373	0	645,373	0	645,373	14,492	659,865
Accumulated Def. Inv. Tax Credit	0	0	0	0	0	0	0
Net Utility Plant	4,667,107	0	4,667,107	(123,295)	4,543,813	(95,133)	4,448,680
Deferred Programs & Investments	24,315	0	24,315	0	24,315	(5,998)	18,317
Operating Materials & Fuel	76,473	0	76,473	0	76,473	2,378	78,851
Misc. Deferred Credits	(80,099)	0	(80,099)	0	(80,099)	(36)	(80,135)
Unamortized Ratepayer Gains	0	0	0	0	0	0	0
Working Cash	57,429	(12)	57,417	(473)	56,944	830	57,774
Total Average Rate Base	4,745,226	(12)	4,745,214	(123,768)	4,621,446	(97,959)	4,523,487

Actual Averages	Average Outstanding	Percent of Capital	Percent Cost	Weighted Percent Cost
Long Term Debt	2,258,455	48.62%	5.32%	2.59%
Preferred Stock	0	0.00%	0.00%	0.00%
Common Equity	2,386,313	51.38%	7.17%	3.69%
Total	4,644,768	100.00%		6.27%

April 10, 2018

TO: Jesse O. Gorsuch
Davison Van Cleve, PC

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1817
PGE Response to AWEC Data Request No. 010
Dated April 1, 2019

Request:

Reference Nicholson - Bekkedahl / 12-13. At lines 17-18 of page 13, PGE states that each listed deferral except for two are "a function of statute or Commission requirements." Please provide the statutory or Commission order reference PGE relies on for this statement for each applicable deferral.

Response:

Attachment 010-A provides the requested information.

- UM 1103 – Intervenor funding – SB 205 and Commission Order 03-388
- UM 1294 – Power costs for Schedule 126 PCAM – Commission Order 07-015
- UM 1301 – Direct access open enrollment – Commission Orders 06-528 and 07-015
- UM 1417 – Decoupling – Commission Order 09-020
- UM 1482 – Photovoltaic volumetric incentive rate pilot – HB 3690 and Commission Order 11-339
- UM 1514 – Non-residential demand response (two pilots) – Commission Order 08-245
- UM 1708 – Residential demand response (Flex pricing and DLC thermostats) – Commission Orders 08-245 and 15-203
- UM 1827 – Water heater pilot – Commission Order 08-245
- UM 1915, UM 1986, etc. – Three deferrals to support balancing accounts – Staff report as adopted by Commission Order 19-020.
- UM 1920 – 2018 tax refund – Commission Order 18-464
- UM 1938 – Transportation Electrification (three pilots) – SB 1547 and Commission Order 18-054
- UM 1966 – Third Party Consultants – Commission Orders 06-446 and 13-204
- UM 1976 – DER Testbeds – Commission Order 17-386
- UM 1977 – Community solar start-up costs – SB 1547 and Commission Order 17-232
- UM 1991 – R&D Tax Credits – Commission Order 18-464
- UM 1999 – Residential energy storage – HB 2193 and Commission Order 18-290
- UM 2003 – Electric Vehicle Charging (two pilots) – SB 1547 and Commission Order 18-054

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1817

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
Application for the Deferral of Storm-Related Restoration Costs.	)
	)
	)

EXHIBIT AWEC/103

2008-2017 ACTUAL LEVEL III STORM DAMAGE LOSSES

(EXHIBIT PGE/801 FROM DOCKET NO. UE 335)

2008 - 2017 Actual Level III Storm Damage Losses

CPI	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
2008	$ 5,936,058									
2009	-0.32%	$ 2,106,514								
2010	1.64%	1.64%	$ -							
2011	3.14%	3.14%	3.14%	$ -						
2012	2.08%	2.08%	2.08%	2.08%	$ -					
2013	1.47%	1.47%	1.47%	1.47%	1.47%	$ -				
2014	1.61%	1.61%	1.61%	1.61%	1.61%	1.61%	$ 5,623,875			
2015	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	0.12%	$ 5,161,601		
2016	1.28%	1.28%	1.28%	1.28%	1.28%	1.28%	1.28%	1.28%	$ 4,504,081	
2017	2.54%	2.54%	2.54%	2.54%	2.54%	2.54%	2.54%	2.54%	2.54%	$ 11,351,424
2018	2.39%	2.39%	2.39%	2.39%	2.39%	2.39%	2.39%	2.39%	2.39%	2.39%
2019	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%	2.41%
2019 $	$ 7,116,504	$ 2,533,532	$ -	$ -	$ -	$ -	$ 6,131,009	$ 5,620,389	$ 4,842,643	$ 11,902,883

Ten Year Total Level III Storm Damage Losses	$ 38,146,960
Ten Year Avg Level III Storm Damage Losses	$ 3,814,696
Average Level III Storm Damage Losses	$ 6,357,827

Year	Level III Storm Actuals	CPI
2008	$ 5,936,058	3.81%
2009	$ 2,106,514	-0.32%
2010	$ -	1.64%
2011	$ -	3.14%
2012	$ -	2.08%
2013	$ -	1.47%
2014	$ 5,623,875	1.61%
2015	$ 5,161,601	0.12%
2016	$ 4,504,081	1.28%
2017	$ 11,351,424	2.54%
2018		2.39%
2019		2.41%

	Collection	Withdrawals	Balance
2011	$ 2,000,000	$ -	$ 2,000,000
2012	$ 2,000,000	$ -	$ 4,000,000
2013	$ 2,000,000	$ -	$ 6,000,000
2014	$ 2,000,000	$ 5,623,875	$ 2,376,125
2015	$ 2,000,000	$ 5,161,601	$ (785,476)
2016	$ 2,000,000	$ 4,504,081	$ (3,289,557)
2017	$ 2,000,000	$ 11,351,424	$ (12,640,981)