Portland General Electric
121 SW Salmon Street • Portland, Ore. 97204
PortlandGeneral.com

March 27, 2019

Public Utility Commission of Oregon
201 High St. SE, Ste. 100
PO Box 1088
Salem OR 97308-1088

Attention: Filing Center

Re: UM 1817 PGE Deferral of Storm Related Restoration Costs

On March 12, 2019 Portland General Electric Company (PGE) requested the Commission establish contested case procedures in docket UM 1817. In accordance with Order No. 19-085 and the procedural schedule set March 13, 2019, PGE submits the following:

- PGE Exhibit 100 – Direct Testimony of Bill Nicholson and Larry Bekkedahl.

If you have questions regarding this testimony, please contact Alex Tooman at (503) 464-7623. All formal correspondence, questions, or requests should be directed to pge.opuc.filings@pgn.com.

Thank you,

Stefan Brown
Manger, Regulatory Affairs

SB/np
Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UM 1817

Deferral of Excess Costs Associated
with 2017 Level III Storm Restoration

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Bill Nicholson
Larry Bekkedahl

March 27, 2019

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Bill Nicholson. I am Vice President of Utility Technical Services.

My name is Larry Bekkedahl. I am Vice President of Grid Architecture, Integration and Systems Operations.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. We support PGE's request for the deferral of excess costs associated with 2017 Level III storm[1] service restoration.

Q. What is PGE's request in this docket?

A. PGE requests Public Utility Commission of Oregon (Commission or OPUC) authorization to defer approximately $9.4 million incurred between January 11, 2017 and year-end 2017 to provide customers with timely service restoration during and following several Level III storms.

Q. What elements of the applicable statute are you referencing in this testimony?

A. For the purposes of this application, we discuss the portion of ORS 757.259(2)(e), which states that anyone proposing to defer costs or revenues show that they are identifiable utility expenses or revenues, the recovery or refund of which the Commission finds should be deferred in order to minimize the frequency of rate changes or the fluctuation of rate levels or to match appropriately the costs borne by and benefits received by ratepayers.

---

[1] We use the terms "major storms," "major events," and "Level III storms/events" interchangeably in this testimony.

Q. Are the costs PGE requested to defer identifiable?

A. Yes. These costs were incurred due to Level III events causing damage to PGE's transmission and distribution (T&D) system. Pursuant to Commission Order No. 10-478, from Docket No. UE 215 (UE 215) and the intent of the settlement regarding storm damage, one of the following criteria had to be met for an event to be considered Level III:

1. Impacts at least 50,000 customers; or
2. Qualifies for Institute of Electrical and Electronics Engineers (IEEE) Major Event Day exclusion;[2] or
3. Several substations and feeders are out of service.

Q. Will this deferral appropriately match the costs borne by and the benefits received by customers?

A. Yes. It is appropriate that customers pay for prudently incurred costs of providing service, which include costs associated with major storm restoration. As explained above, Level III storm restoration costs were incurred to rapidly restore service to customers during and following Level III events. Absent this deferral, customers will have received service at a cost significantly less than PGE prudently incurred to provide it.

[2] An IEEE Major Event Day exclusion is a day in which our daily System Average Interruption Duration Index (SAIDI) exceeds a threshold value. In 2017, the T_{med} was 4.84 minutes. If our accrued daily SAIDI minutes exceed the threshold, that day is considered a major event day (MED) and is analyzed separately from events occurring on days that are not MEDs for PGE's annual reliability reports, pursuant to OAR 860-023-0151.

II. 2017 Major Storm Deferral

Q. Please briefly describe PGE's storm restoration efforts.

A. During a severe weather event, all available field workers and on-site line contractors are dispatched to identify and repair the sources of outages. For instance, over 1,000 field workers and support personnel were deployed during our April 2017 wind storm to restore service for approximately 185,000 customers who were out of power at the peak of the event. PGE also responds to '911' calls of downed power lines and de-energizes these lines to mitigate unsafe conditions. Depending on the severity of the event and the number of outages being experienced, we may also request contractors from outside our service territory, as well as mutual aid from other utilities, to assist us with storm restoration efforts.

Q. Did PGE recover some of the costs resulting from the 2017 storm restoration efforts?

A. Yes. PGE collected $2.0 million in 2017 to pay for service restoration costs in relation to Level III events. The $2.0 million was an annual accrual amount established in 2011 and remained unchanged through 2017 based on a continuation of the storm accrual mechanism approved by Commission Order No. 10-478. The annual storm accrual is calculated as a rolling ten-year average of historical Level III storm costs, adjusted to reflect present value costs (i.e., escalated for inflation).[3]

Q. Is PGE seeking recovery of costs already covered by the major storm accrual mechanism?

A. No. PGE is not seeking recovery of $2.0 million already included in prices.

Q. How many major storms did PGE experience in 2017?

---

[3] PGE currently collects $3.8 million based on the rolling ten-year average of Level III storm costs from 2008 to 2017 as set in PGE's 2019 general rate case, Docket No. UE 335.

A. In 2017, PGE experienced four Level III storms (plus a fifth storm that nearly qualified as a Level III event), resulting in approximately $11.4 million in Level III storm restoration costs, far exceeding PGE's storm accrual of $2.0 million.

Q. Has the Commission provided guidance on how it will exercise its discretion in applying the criteria from ORS 757.259 to defer such costs?

A. Yes. In Docket No. UM 1147, Order No. 05-1070 at 7, explained:

> The Commission will look to whether the event was modeled in rates and, if so, whether extenuating circumstances were involved that were not foreseeable during the rate case, or whether the event fell within a foreseen range of risk when rates were last set. If the event was not modeled, we will consider whether it was foreseeable as happening in the normal course of events, or not likely to have been capable of forecast. … If the event was modeled or foreseen, without extenuating circumstances, the magnitude of harm must be substantial to warrant the Commission's exercise of discretion in opening a deferred account. If the event was neither modeled nor foreseen, or if extenuating circumstances were not foreseen, then the magnitude of harm that would justify deferral likely would be lower.

Q. How did the OPUC Staff characterize Level III storm costs in Docket No. UE 335 testimony and in its memo to the Commission in Docket No. UM 1817?

A. Staff asserted that the Commission has previously reasoned that stochastic risks modeled in rates represent "reasonable risk" that PGE assumes as part of the normal course of utility operations. Staff also asserted that while the Commission has not set a precise numeric criterion to define a threshold level of risk for deferrals, excess net variable power costs (NVPC) that were equal to or less than 250 basis points of PGE's return on equity (ROE) was an amount that could be reasonably absorbed. Based on Staff's calculation that 2017 storm costs represent an amount equal to approximately 47 basis points of PGE's authorized ROE, they assert that this amount is well below what the Commission has indicated to represent reasonable risk.[4]

Q. Is Staff's reference to NVPC and the magnitude of its financial impact a meaningful comparison for discussing Level III storm costs?

A. No. Other than Staff's reference to NVPC, Staff does not provide any basis to claim that 47 basis points of authorized ROE is "well below what the Commission has indicated represents reasonable risk for utilities in between rate cases."[5] Further, when Staff presented a matrix with requirements for a deferral request that detailed the type of risk (i.e., stochastic or scenario) and financial impact (i.e., substantial or material) for cost recovery of a deferral, the Commission declined to adopt it for future use, choosing instead to exercise its discretion.[6]

For additional context, at the time when the Commission referenced a 250 basis-point deadband for power costs in Order No. 04-108, PGE's NVPC exceeded $750 million in 2002 and exceeded $500 million in 2003 and 2004. By way of more applicable comparisons, PGE's T&D restoration costs as included in our 2016 test year forecast (Docket No. UE 294[7]) amounted to: $2.0 million for Level III events, $1.8 million for Level I and II events, and $14.0 million for non-weather-related restoration work. In short, the $11.4 million incurred for Level III restoration in 2017 amounted to:

- Almost six times the amount included in prices for Level III events;
- Over 70% of the total amount included for all restoration work; and

---

[4] Staff/600, page 6, lines 11-12 (UE 335); Staff Memo, pages 3-4 (UM 1817)
[5] Staff/700, page 6, lines 11-12.
[6] Commission Order No. 05-1070, page 7; Docket No. UM 1147.
[7] Because PGE did not file a 2017 general rate case, the 2016 general rate case (UE 294) established the then-current storm accrual of $2.0 million.

- Approximately 14% of the total T&D operations and maintenance (O&M) forecast for the 2016 test year.[8] For 2017 in total, PGE's actual Distribution O&M expense exceeded budget by approximately $18 million.

Ultimately, a determination of the 2017 storm restoration deferral should reflect a meaningful comparison of relevant costs. Although Staff suggests that a deadband applies, they do not give any indication of the basis for this assertion other than vague references to NVPC, which bear no relationship to storm restoration costs.

Q. Was the severity of the 2017 Level III storm season modeled in rates or foreseeable as happening in the normal course of events?

A. No. We establish the Level III storm accrual using a 10-year rolling average of the most recent historical cost data. For example, to estimate 2016 (and hence 2017) Level III storm costs, we used the average of Level III storm costs from 2005-2014.

Q. Is a 10-year rolling average a stochastic modeling approach?

A. No. Stochastic modeling, to which Staff references, is a tool for estimating probability distributions of potential outcomes by allowing for random variation in one or more inputs based on time-series techniques. Because of the simplicity of the 10-year rolling average, it serves as a proxy for estimating Level III storm costs but does not represent stochastic modeling and does reflect all the factors that influence the severity and costs associated with Level III events.

In addition, the magnitude of 2017 storm severity was not foreseeable as happening in the normal course of events, based on the level of storm activity that PGE had experienced

[8] This excludes Information Technology (IT) costs as assigned or allocated to T&D. Including IT costs, the $11.4 million still accounted for more than 10% of total T&D O&M.

over the previous 20 years. As noted by the Oregon Citizens' Utility Board (CUB) in Docket No. UE 335 (UE 335):

- 2017 was an unusual year for storms and an outlier.[9]
- 2017 was a one in 18 years for Level III storm costs.[10]
- The January 2017 snowstorm was characterized by the National Weather Service as a one in 25-year storm.[11]

Q. Based on these observations did CUB or other parties comment on PGE's potential for filing deferrals related to excessive storm costs?

A. Yes. In UE 319 and UE 335 (PGE's 2018 and 2019 general rate cases) Staff and CUB addressed PGE's potential for filing deferrals related to storm restoration costs. In both instances, they were arguing against PGE's proposal to establish a balancing account for its storm accrual. In UE 335, CUB argued that "Given that a Company can file for a deferral in high storm cost years, as it has in the past, it is not necessary for the Company to be able to hold a negative balance in storm expenses."[12] In Docket UE 319, Staff stated it does not believe "that extraordinary ratemaking treatment is warranted, particularly in light of the fact that PGE may file for a deferral pursuant to ORS 757.259 if costs from a particular storm are significant."[13]

This creates a contradiction. Staff and CUB admit that PGE can file for deferrals related to significant storm restoration costs, but then Staff would impose a threshold that is

---

[9] CUB Exhibit 200, page 24, lines 12-13.
[10] CUB Exhibit 200, page 25, lines 4-5.
[11] CUB Exhibit 200, page 25, lines 7-8.
[12] CUB/200, page 27, lines 1-3.
[13] Staff/400, page 31; lines 7-9; Docket No. UE 319.

deliberately indistinct but implicitly large enough to exceed almost any level of expense that might be incurred.

Q. If the 2017 storm restoration costs do not represent stochastic risk, what do they represent?

A. Based on Staff's UM 1147 matrix, Commission Order No. 05-1070, and the detail described above, the 2017 storm costs represents at most a scenario or paradigm risk. They were not foreseeable as happening in the normal course of events and were not modeled in the 10-year rolling average method. Consequently, "the magnitude of harm that would justify deferral [would] likely would be lower."[14]

Q. How do you respond to Staff's assertions that by "setting rates based on past costs, deferred accounting essentially shifts all risk away from investors and onto ratepayers"[15] and that "Setting rates on a forward-looking basis, the Company is thereby incented to control and manage costs"?[16]

A. The storm restoration accrual, as authorized in UE 215, does not establish a level of risk but creates an amount to collect in prices based on historical averages. Further, the referenced incentive to control and manage costs does not apply to storm restoration as it does most other costs.

Q. Please explain.

A. For most types of costs, actual amounts will not equal PGE's corresponding test year forecast. Some costs will be over that forecast, others will be under, and some costs can be temporarily postponed if conditions warrant. PGE agrees that it is appropriate to manage this interaction

[14] Commission Order No. 05-1070, page 7.
[15] Staff/700, page 5, lines 12-13.
[16] Staff/700, page 5, lines 8-9.

of costs and accept a level of business risk as part of its authorized return on equity. Storm restoration costs as experienced in 2017, however, are not part of that calculus. First, as noted above, the storm restoration mechanism is based on historical averages, not a forward-looking basis. When storms occur, PGE makes every effort to restore power as quickly as possible. This is expected of us by customers, by the Commission, and by ourselves. This level of commitment, however, does not lend itself to limiting costs to a pre-determined amount, especially for severe events. If it did, PGE could delay restoration and incur significantly less overtime and contractor costs. Further, in years when storm restoration costs are below the accrual amount, PGE cannot use that benefit to offset other costs that are over-budget or for increasing ROE because those funds are rolled forward to offset future storm costs. The accrual and associated reserve apply only to storm-related costs, and hence, the net impact on PGE's ROE is asymmetric and negative when storm costs exceed the accrual/reserve. In short, we prudently manage costs to restore service to customers, but do so within the constraint of restoring service to customers as quickly as possible.

Q. If PGE were to receive full cost recovery for all its storm restoration costs, would this create a disincentive to invest in your system or otherwise implement programs to mitigate that risk and limit the damage that can occur from Level III events?

A. No. PGE would have no disincentive to mitigate this risk. First, employees and contractors who physically address the consequences of this risk, are required to do so for long and arduous hours under the worst conditions. No one wants to do that, especially on a prolonged basis due to particularly severe storms or a series of severe events. Second, PGE is committed to restore power to customers as quickly as possible under all situations. This activity is a core utility function in service to our customers and we have established specific corporate scorecard goals to meet customer satisfaction levels and system reliability goals. When PGE does not meet our customers' outage restoration expectations, overall customer satisfaction declines. Performing poorly on reliability and outage restoration today is even more impactful than it was 10 years ago and places more emphasis on this activity.

Q. Is PGE proactively investing in its infrastructure to mitigate the impact of storm damage before it occurs?

A. Yes. In PGE's 2016 general rate case (Docket No. UE 319), we introduced PGE's new robust and proactive asset management strategy to reduce risk. A key component of this effort is the Strategic Asset Management department (SAM), which prepares an annual T&D risk assessment and associated portfolio of recommended risk reduction projects. The SAM accomplishes this by having developed a risk assessment method that employs industry best practices criteria to quantify threats to the grid and evaluate the impacts to customers should portions of the system fail. SAM's risk assessment approach encourages a long-term plan that cost-effectively reduces risks (including reliability, safety, environmental, and cost efficiency) and supports customer demand.

Q. Please briefly describe the risk assessment method.

A. SAM identifies system improvements that demonstrate maximum value to customers in terms of risk reduction. This is accomplished by quantifying the existing risk associated with specific assets and the potential benefit of system improvements to determine optimal investment in infrastructure. In summary, this is a rigorous process based on quantified risks and benefits to customers and would not be disincentivized or otherwise impacted by cost recovery for Level III events.

Q. What proactive, SAM-based investment relates to mitigating storm restoration risk?

A. To address storm mitigation, we are considering non-asset risk as opposed to asset risk. Asset risk is associated with the electrical infrastructure that serves customers. This type of risk is more predictable and accounts for approximately one-third of annual outages. Non-asset risk is associated with external factors that impact electrical infrastructure, thus service to customers. Examples include weather, vegetation, animal contact, and vehicles hitting power-line poles. To cost-effectively mitigate these risks, SAM considers the potential for outages and solutions to limit the occurrence and/or extent of an outage event, if it were to occur. The following are examples of efforts to mitigate non-asset risk related to weather that are evaluated annually:

- Transitioning overhead conductor to undergrounding conductor is a very effective but costly method of mitigating storm risk, so it is used in limited circumstances. The effectiveness of this method, however, is observable in fully undergrounded downtown Portland where reliability is near 100%.
- System hardening with tree wire is effective in areas with significant tree growth in the vicinity of wires. Where cost-effective to do so, PGE will install tree wire (i.e., conductor covered with insulation). This will limit the potential for an outage when portions of trees contact the wire during wind, snow, and/or ice storms.
- Vegetation management is applied throughout PGE's service territory but is more pronounced in certain corridors where additional effort is justified.
- Distribution automation refers to intelligent devices that are installed to detect, isolate, and restore power to more customers in an automated, in lieu of manual, fashion. Significantly less response and restoration efforts are required with this

functionality, thus reducing outage durations for customers on circuits equipped with distribution automation.

- Trip saving refers to "smart" fuses that are deployed in place of traditional, standard fuses at tap lines to help avoid outage events, durations, and/or reduce the number of customers impacted by an outage event.

Q. In additional UM 1817 comments to the Commission, the Alliance of Western Energy Consumers (AWEC) and the Oregon Citizens' Utility Board (CUB) claim that PGE has moved away from principles related to deferred accounting as an exceptional form of rate making and one that should be used sparingly.[17] How do you respond?

A. AWEC and CUB state that by their count, PGE has at least 11 deferred accounting petitions pending before the Commission.[18] In reality, PGE has numerous active deferrals that are being pursued based on Commission orders and/or, statutory requirements. Ultimately, the following deferrals represent costs that are not regular and on-going and should not be included in base rates. Because PGE is being required to incur these costs, however, it would not be reasonable to insist that they be absorbed by shareholders based on assumptions regarding deadbands or thresholds.

- Demand response pilots, which are in an early stage of implementation, learning, and evaluation (e.g., testbeds).
- Demand response pilots in the process of moving to the program stage, but are neither mature nor stable (e.g., Flex pricing).
- Developmental pilots for energy storage and transportation electrification.

---

[17] AWEC and CUB comments, page 3, UM 1817.
[18] AWEC and CUB comments, page 3, UM 1817.

- Photo voltaic feed-in tariff
- R&D tax credits and 2018 income tax refund
- Decoupling
- Direct access open enrollment
- Power costs related to qualifying facilities
- Power costs for Schedule 126 power cost adjustment mechanism
- Community solar
- Independent evaluator and third-party consultant to review/validate resource proposals
- Intervenor funding
- Support for balancing accounts (e.g., major maintenance accruals). In this instance, PGE attempted to file one consolidated deferral application for multiple balancing accounts, but the resulting Commission order requires PGE to file three separate applications. In addition, these filings do not result in subsequent amortizations. Instead, they provide additional regulatory support for long-standing, approved, balancing account mechanisms that are intended to achieve zero balances over time.

Although PGE has the above-listed deferrals pending and/or active, we have only two deferrals that are not a function of statute or Commission requirements – 2017 storm restoration costs and Portland Harbor environmental remediation costs. Consequently, we believe that this deferral application is appropriate within the Commission's principles and should be approved.

Q. How would recovery of the 2017 storm deferral impact an earnings review and PGE's prices?

A. PGE's regulated adjusted ROE as listed in our 2017 Results of Operations Report, filed April 25, 2018, was 7.90%. This is 170 basis points below PGE's authorized ROE of 9.6% as determined in PGE's 2016 general rate case (Commission Order No. 15-356, Docket No. UE 294). Full recovery of the $9.4 million storm deferral would result in:

- A 2017 regulated adjusted ROE of 8.3%, which is still 130 basis points below PGE's then-authorized rate; and
- An overall average price increase of approximately 0.5% compared to total forecasted 2019 revenues and assuming a one-year amortization. This would be a one-time price increase that would terminate at the end of the amortization period.

III. Summary and Conclusions

Q. Please summarize your testimony.

A. PGE employs a rigorous approach to cost-effectively invest in our T&D system to mitigate non-asset risk. Notwithstanding these investments, Level III events cause damage to the system and extensive customer outages. When Level III events occur, however, PGE makes every effort to restore power to customers as quickly as possible under all situations. Due to the number and severity of Level III events in 2017, PGE incurred extraordinary costs to restore service to customers, and as a result, we filed for deferred accounting treatment for the 2017 storm restoration costs in excessive of the amount included in prices. Further, based on the magnitude of these costs in relation to the amount recovered in prices, they do not represent stochastic risk. Finally, stochastic modeling was not employed to determine the amount to include in prices for storm restoration costs.

Q. What is the consequence of the use of a non-stochastic modeling approach to storm costs in prices.

A. There are two chief consequences. First, it means the application of the policy framework from UM 1147 can only conclude that the risks associated with storms is event/scenario risk. Second, and more important, it means that one cannot reasonably conclude that the amount in prices to recover major costs are somehow designed to balance costs and revenues over multiple years. Thus, absent the use of deferred accounting, PGE does not have a reasonable opportunity to recover its prudently incurred cost of service in years such as 2017.

Q. Please summarize your request of the Commission.

A. PGE requests that, absent an effective balancing account mechanism, 2017 storm restoration costs should be authorized for deferral because they are prudently incurred and based on uncompromising expectations for rapid service restoration. The 2017 storm restoration costs were significant and unforeseen as evidenced by the fact that they were almost six times higher than the amount allowed in prices for Level III work and over 70% of the total amount included in prices for all restoration work. Finally, with full recovery of this deferral, PGE's 2017 regulated adjusted ROE would still be 130 basis points below authorized.

IV. Qualifications

Q. Mr. Nicholson, please describe your educational background and qualifications.

A. I received a Bachelor of Science Degree in Nuclear Engineering from Oregon State University. I completed the Harvard University Program on Negotiation and graduated from the Public Utilities Executive course at the University of Idaho. I am a registered professional engineer in the State of Oregon and I belong to the National Society of Professional Engineers. My employment with PGE started in 1980 as an engineer at the Trojan Plant and I have served in a variety of capacities in Distribution Operations, Generation Engineering and Resource Development. In May 2007, I became Vice President of Customers & Economic Development and in August of 2009, I was appointed Vice President of Distribution. In April of 2011, I assumed the role of Senior Vice President of Customer Service and Delivery, and in 2019, I assumed my current role of Vice President of Utility Technical Services.

Q. Mr. Bekkedahl, please describe your educational background and qualifications.

A. I received a Bachelor of Science Degree in Electrical Engineering from Montana State University. I serve on the Electric Power Research Institute's Power Delivery executive committee, as a U.S. board member for the International Council on Large Electric Systems (CIGRE). My employment with PGE started in August 2014 as Vice President of Transmission and Distribution. Prior to that, I served as Senior Vice President for Transmission Services at the Bonneville Power Administration (BPA), and have held other leadership and management positions at BPA, Clark Public Utilities, PacifiCorp and Montana Power Company. I also have international utility experience gained by participating in a six-month exchange program with Hokuriku Electric Power Company in Toyama, Japan, developing hydro projects in the Philippines, and participating in United States Agency for

International Development (USAID) exchange projects in Bangladesh, the Republic of Georgia, and the Philippines. In 2019, I assumed my current role of Vice President of Grid Architecture, Integration and Systems Operations with PGE.

Q. Does this conclude your testimony?

A. Yes.