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Public Utility Commission
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July 18, 2018

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 1088
SALEM OR 97308-1088

RE: Docket No. UM 1953 – In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Investigation into Proposed Green Tariff.

Enclosed for electronic filing is Staff's Response Testimony - Exhibit 100-102.

/s/ Kay Barnes
Kay Barnes
Filing on Behalf of Public Utility Commission Staff
(503) 378-5763
Email: kay.barnes@state.or.us

CASE: UM 1953
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Response Testimony

July 18, 2018

Q. Please state your name, occupation, and business address.

A. My name is Lance Kaufman. I am a Senior Economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. My testimony provides analysis of and recommendations for PGE's voluntary renewable energy tariff (VRET) filing.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared exhibit Staff/101 Witness Qualification and Staff/102 Responses to Data Requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. VRET BACKROUND AND SUMMARY OF PGE'S FILING

Q. Please provide background related to PGE's VRET filing.

A. During the 2014 regular session, the Oregon Legislature passed House Bill 4126 (HB 4126). This bill directed the Commission to study the impacts of allowing utilities to offer a voluntary renewable energy tariff to customers.[1] The bill also provided the Commission with authority to allow such tariffs, following a determination by the Commission that it is reasonable and in the public interest to allow the electric company to provide a VRET to its nonresidential customers.[2] HB 4126, Section 3(4) states:

> If the commission determines under subsection (3) of this section to allow electric companies to offer voluntary renewable energy tariffs to nonresidential customers, the commission may authorize an electric company to file a schedule with the commission that establishes the rates, terms and conditions of services offered under the voluntary renewable energy tariff. All costs and benefits associated with a voluntary renewable energy tariff shall be borne by the nonresidential customer receiving service under the voluntary renewable energy tariff.

In accordance with the direction from the legislature, the Commission opened Docket No. UM 1690 and directed Staff to conduct a study to consider the impact of allowing electric companies to offer VRETS to their non-residential customers.[3] The Commission accepted the Study in Phase 1.[4] In Phase 2, the Commission adopted guidelines for VRETs that may be found in the public

[1] HB 4126 Section 3(2).
[2] HB 4126 Section 3(3).
[3] *In re Public Utility Commission of Oregon*, OPUC Docket No. UM 1690, Order No. 15-258 at 1 (Aug. 26, 2015).
[4] *Id.*

interest, and encouraged utilities to file draft VRETs designed in accordance with the nine guidelines:

1. Renewable Portfolio Standard (RPS) definitions for resource type, location, and bundled Renewable Energy Certificates (RECs) must apply to VRET products.
2. VRET options should only include bundled REC products. Any RECs associated with serving participants must be retired by or on behalf of participants, unless the participants consent to RECs being retired by the utility or the developer.
3. The year in which a VRET eligible renewable resource became operational should be no earlier than 2015.
4. The VRET program size is limited to 300 aMW for PGE and 175 aMW for PacifiCorp.
5. VRET product design should be sufficiently differentiated from existing direct access programs.
6. VRET terms and conditions (including the timing and frequency of VRET offerings), as well as transition costs, must mirror those for direct access. PGE and PacifiCorp may propose VRET terms and conditions that differ from current direct access provisions but must proposed changes to their respective direct access programs to match those changes.
7. The regulated utility may own a VRET resource, but may not include any VRET resource in its general rate base. It may recover a return on and return of its investment in the VRET resource from the VRET customer; however, the utility must share some of the return on with other utility customers for ratepayer-funded assets used to assist the VRET offering.
8. All direct and indirect costs and risks are borne by the VRET customers, shareholders of the utility, or third-party developers and suppliers with provisions allowing independent review and verification by the Commission Staff of all utility costs. Costs include but are not limited to ancillary services and stranded costs of the existing cost of service rate based system.
9. All VRET offerings must be made publicly available and subject to review by the Commission to ensure they are fair, just, and reasonable.[5]

The Commission ultimately decided to defer its decision as to whether, and under what conditions, it is reasonable and in the public interest to allow electric companies to provide VRETs to nonresidential customers.[6] Instead,

[5] Order 15-405 at 1-2.
[6] *Id.*

the Commission indicated it would make this determination with the benefit of a program designed by an interested electric utility.[7]

Q. Please summarize PGE's proposal for a VRET.

A. PGE proposes that it will purchase renewable energy through a PPA. All Cost of Service (COS) customers will pay for the energy and capacity associated with the PPA at the qualified facility (QF) rates listed on Schedule 201. Customers receiving service under the VRET will pay the COS rate, plus the difference between the QF rate and the PPA cost. PGE shareholders will pay the VRET rate for the unsubscribed portion of the PPA. VRET customers may also pay a risk premium depending on the commitment length and PPA subscription rate.

Q. What are Staff's primary observations and concerns with the VRET filing?

A. Staff appreciates PGE's effort in moving forward with a VRET proposal. PGE's filing is consistent with many of the VRET guidelines provided by the Commission. Staff has some concerns about PGE's proposal; however, in this testimony Staff outlines a path forward that would allow customers access to voluntary renewable energy without adverse impacts on either general cost of service customers or competitive markets. Staff's primary concerns are:

1. PGE's VRET proposal may increase costs and risks for non-VRET customers.

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[7] *Id.*

2. PGE has not demonstrated how VRET rates are calculated or how the program compares to existing direct access offerings.

Q. What are Staff's recommendations?

A. Staff recommends that:

1. PGE use a forward-looking net power cost model to calculate the energy credit for the PPA.
2. PGE apply the same methodology to calculate capacity value of the PPA as it does for the capacity value of long-term direct access.
3. PGE apply a consistent theory of cost-shifting for VRET and direct access programs.
4. PGE clarify the treatment of integration and transmission costs.
5. PGE provide workpapers illustrating how administrative and marketing costs will be tracked and allocated.
6. PGE allocate additional capital carrying costs associated with the VRET to VRET customers.
7. PGE provide workpapers illustrating all costs, charges, and rate calculations using data and detail that are representative of the types of PPA agreements that PGE anticipates entering into.
8. PGE provide sample agreements for VRET participants that illustrate terms of commitment and consequences for violating those terms.
9. PGE provide additional detail on how the risk premium is calculated and accounted for.
10. PGE provide a side by side comparison of direct access and VRET rates.

11. PGE include language in its tariff that prevents the total rate under the VRET from being below the total rate under COS.

Q. How do Staff's concerns and recommendations relate to the VRET guidelines?

A. Staff's concern regarding cost-shifting relates to guidelines six and eight. Staff's concern regarding VRET rate calculations relates to guidelines five, six, and nine.

ISSUE 2. VRET COST SHIFTING

Q. Why should the Commission be concerned that the VRET proposal may increase costs and risks for COS customers?

A. House Bill 4126 requires the Commission to consider, when determining whether and under what conditions a VRET may be reasonable and in the public interest, "[a]ny direct or indirect impact, including any potential cost-shifting, on other customers of any electric company offering a [VRET]."[8] The legislation also provides that "[a]ll costs and benefits associated with a [VRET] shall be borne by the nonresidential customer receiving service under the [VRET]."[9] Allocating costs based on causation helps to ensure efficient decision making by both customers and the utility.

Further, VRET Guideline 7 provides that "[t]he utility must demonstrate that there is no risk or cost shifting on nonparticipating customers due to any direct or indirect VRET service and resource obligations, including stranded costs of the existing cost of service rate based system."[10]

Q. Please explain why PGE's proposal may allow VRET related costs and risks to be borne by non-VRET customers.

A. With regard to cost shifts, PGE's VRET draft does not sufficiently address the following costs and risks:

1. Capacity and energy credit for PPA:
    a. Excess valuation of capacity and energy;

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[8] HB 4126 Section 3(3).
[9] HB 4126, Section 3(4).
[10] Order 16-251, Appendix A at 8.

b. Risk of excess capacity and energy; and

c. Mismatch between ancillary service requirements for capacity needs and capacity acquisition.

2. Marketing and administrative costs:

a. Cost of developing and maintaining customer marketing data;

b. Cost of acquiring PPAs; and

c. Cost of IT solutions enabling green tariffs.

3. Cost of capital impacts:

a. Additional shareholder risk.

Capacity and Energy Credit for PPA

Q. What concern does Staff have related to the Capacity and Energy Credit for the PPA?

A. PGE proposes to use QF avoided cost rates as the basis for capacity and energy credits for the PPA. This raises several concerns for Staff.

First, the QF rate may provide too much value for capacity and energy of the PPA. The QF rate is designed to mitigate the transactional cost of small energy providers and is applicable to all small generators. As such, it may not accurately reflect the value of individual PPAs.[11] Even PGE declines to acknowledge that current QF rates reflect PGE's avoided costs.[12] As explained by PGE, "PURPA's mandatory purchasing obligation significantly and unnecessarily increases the costs of decarbonizing the electricity sector for

[11] *See* Docket No. UM 1734, Staff/100, Andrus/2-4.
[12] Staff/102 - PGE's response to Staff DR 4.

PGE's customers because PURPA contracts lack the planning and cost scrutiny undertaken for other resource decisions. PURPA should be modernized to achieve the law's intent in today's renewable energy economy while protecting utility customers from excessive costs."[13] Moreover, large energy producers have been structuring their projects as small projects to qualify for the QF rate, demonstrating an incentive as compared to larger projects. This further supports the conclusion that the QF rate may not be appropriate for VRET PPAs.[14]

Second, PGE's proposal to acquire PPAs based on VRET customer subscription may not align with PGE's capacity and energy needs. PGE proposes to acquire PPAs outside of the planning framework used for other capacity additions. However, if PGE's actual capacity needs occur later than expected, the PPA capacity credit will not line up with the capacity need. Conversely, if lower cost capacity options arise before the capacity need is realized, the PPA may not be the least cost solution to capacity needs.

Finally, the ancillary services of the PPA may not reflect those of the optimal capacity expansion resource. PGE faces a 50 percent renewable resource requirement in the near future, which may result in large renewable additions to PGE's system. Renewable resources place stresses on the grid that may require PGE to obtain additional ancillary services, including ramping capabilities. Capacity expansions, such as Port Westward 2, can help serve

[13] Staff/102 - PGE's response to Staff DR 6, Attachment A.
[14] *See* Docket No. UM 1734, Staff/100, Andrus/17-22.

ancillary service needs as well as capacity needs. The PPA's acquired for VRET customers may not provide the same ancillary services as the optimal capacity expansion choice, increasing costs for COS customers.

Marketing and Administrative Costs

Q. What marketing and administrative costs may not be addressed by the VRET draft?

A. PGE has not provided a detailed explanation or supporting workpapers demonstrating how PGE will track VRET marketing and administrative costs. Regarding marketing costs, PGE has not indicated that any marketing costs are included in the VRET rates. PGE maintains a marketing database on customer renewable preferences,[15] and populates this database using PGE's customer information systems and PGE's customer service center.[16] This database provides PGE with a competitive advantage in marketing renewable services to customers relative to direct access marketers--an advantage which is paid for by COS customers. The costs of acquiring and maintaining marketing information should be identified and included in the VRET rate.

Regarding administrative costs, PGE has indicated that such costs will be included in the VRET rate. However, PGE has not provided workpapers demonstrating how these costs will be calculated. Some of the costs of administering the VRET program may be common costs with COS customers and will be difficult for PGE to directly track. For example, it is not clear how

[15] Staff on-site review of PGE's customer service center.
[16] Staff on-site review of PGE's customer service center.

the costs of PGE's billing system, which allows for complex billing required by the VRET, will be allocated to VRET customers. It is also not clear how the cost of PGE's procurement department, which will be procuring PPAs for both VRET customers and COS customers, will be allocated between VRET and COS customers. PGE needs to provide more detail on how it will track and allocate these costs.

Cost of Capital Impacts

Q. How does the VRET affect PGE's cost of capital?

A. PGE proposes that shareholders will bear the risk of under-subscription by VRET customers to PPAs. This increase in risk may increase PGE's cost of capital because investors expect additional compensation for additional risk. It is possible that this increased cost of capital is transferred back to customers through PGE's return on rate base. PGE does not have a plan to track and mitigate the effect of this risk increase on cost of capital estimates.[17] Although PGE has indicated it may include a risk premium in the VRET charge, PGE has not provided a detailed description of how this premium will be calculated or accounted for.[18] The premium should be priced and accounted for in a manner that fully mitigates the effect of the VRET risk on COS customers.

Q. Which Staff recommendations address the potential for the VRET to shift cost and risks to COS customers?

[17] Staff/102 PGE's response to Staff DR 15.
[18] Staff/102 PGE's response to Staff DR 16.

A. Staff recommendations 1 through 6 relate to the cost-shifting issue. To address the risks identified above, Staff recommends:

1. PGE use a forward-looking net power cost model to calculate the energy credit for the PPA.
2. PGE apply the same methodology to calculate capacity value of the PPA as it does for the capacity value of long-term direct access.
3. PGE apply a consistent theory of cost-shifting for VRET and direct access programs.
4. PGE clarify the treatment of integration and transmission costs.
5. PGE provide workpapers illustrating how administrative and marketing costs will be tracked and allocated.
6. PGE allocate additional capital carrying costs associated with the VRET to VRET customers.

ISSUE 3. VRET TERMS AND CONDITIONS

Q. What concerns does Staff have with the terms and conditions of the VRET tariff?

A. The terms and conditions of the VRET are presented at a high level, and do not provide sufficient detail to confirm compliance with the VRET guidelines of Order No. 15-405. The following items do not have sufficient detail:

1. VRET Subscription Agreement terms and conditions:
    a. Contract length requirements; and
    b. Early termination consequences.
2. Risk premium pricing and accounting.
3. Ratemaking Treatment when COS credit exceeds PPA costs.
4. PPA generation profiles and characteristics.

Q. Please explain why the proposal should include additional detail.

A. VRET guideline 6 provides that "VRET terms and conditions (including the timing and frequency of VRET offerings), as well as transition costs, must mirror those for direct access. PGE and PacifiCorp may propose VRET terms and conditions that differ from current direct access provisions but must propos[e] changes to their respective direct access programs to match those changes."[19]

[19] Order 15-405 at 2.

Q. Please describe your concerns with VRET Subscription Agreement terms and conditions.

A. PGE's VRET proposal does not address contract length requirements and early termination consequences for VRET subscribers. Both concepts are addressed by the Company's direct access programs. Staff cannot evaluate compliance with guideline 6 without this information. The Company's reply testimony should address what, if any, contract length requirements and early termination consequences will exist for VRET customers, and explain the rationale of those provisions in comparison to how these concepts are addressed by direct access.

Q. Please describe your concerns with risk premium and accounting.

A. PGE has indicated that it may charge VRET customers a risk premium. This premium could be used to prevent COS customers from subsidizing VRET customers and ensures that PGE's offering does not put interfere with the competitiveness of direct access offerings. PGE has not explained how the premium will be calculated and accounted for, and would be left to PGE's discretion to implement. If the risk premium is not calculated correctly, or passed on at all, PGE may be subjecting COS customers to cost shifting and may be placing barriers to the competitiveness of the wholesale energy market.

Q. Please describe your concerns with the ratemaking treatment when COS credit exceeds PPA costs.

A. Under PGE's current proposal, the VRET rate could be less than the COS rate, which would incent all customers to opt for the VRET regardless of renewable preferences. However, when PGE acquires PPAs to serve the increased VRET participation net power costs will likely increase because the QF rate exceeds the net power cost rate. Therefore, the VRET offering may force COS customer to pay more for net power costs than they otherwise would absent the program.

Q. Please explain your concerns with the PPA generation profiles and characteristics.

A. Additional information on this item is necessary in order to understand the capacity and energy value of the PPA. As noted in the prior issue, PGE will face unique requirements for capacity expansion, and the PPA may not serve these requirements. The generation profile will help parties determine how to value the capacity and energy of the PPA.

Q. Please summarize Staff's recommendation to address the above-discussed concerns.

A. Recommendations 7 through 11 address the need for additional details in PGE's proposal:

7. PGE provide workpapers illustrating all costs, charges, and rate calculations using data and detail that are representative of the types of PPA agreements that PGE anticipates entering into.

8. PGE provide sample agreements for VRET participants that illustrate terms of commitment and consequences for violating those terms.
9. PGE provide additional detail on how the risk premium is calculated and accounted for.
10. PGE provide a side-by-side comparison of direct access and VRET rates.
11. PGE include language in its tariff that prevents the total rate under the VRET from being below the total rate under COS.

Q. Please explain why Staff includes recommendations that ensure the VRET has similar terms and conditions as direct access programs, as well as similar methodology for energy and capacity valuation.

A. These programs are similar in that they both result in additional energy available for COS customers. The Commission can leverage the tools developed in Direct Access when evaluating VRETs. The VRET should be structured to minimize cost shifting. Utility direct access programs have already experienced substantial design, analysis, and vetting to ensure that there is no unwarranted cost shifting. Similar terms and conditions will also prevent the VRET offering from undermining the competitiveness of the Oregon energy market.

Q. Please explain why Staff recommends that PGE provide additional detail on the VRET proposal.

A. PGE's filing is not detailed enough to evaluate many of the guidelines for the VRET drafts. For example, guideline six requires that the terms and conditions mirror direct access, and guideline eight requires that all direct and indirect costs and risks be borne by VRET customers. The information provided by the Company is not sufficient to determine if the proposal complies with these guidelines.

Q. Please explain why Staff recommends using a power cost model to define the value of energy from the VRET.

A. The net power cost models provide the most accurate estimate of the value to these resources to the system.

Q. Does this conclude your testimony?

A. Yes.

CASE: UM 1953
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

July 18, 2018

WITNESS QUALIFICATION STATEMENT

NAME:	Lance Kaufman
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Economist Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 9730
EDUCATION:	In 2013 I received a Doctorate degree in economics from the University of Oregon. In 2008 I received a Master of Science degree in Economics from the University of Oregon. In 2004 I received a Bachelor of Business Administration in Economics from the University of Alaska Anchorage.
EXPERIENCE:	From March of 2013 to September of 2014 and from September of 2015 to the present I have been employed by the Oregon Public Utility Commission (OPUC). My current responsibilities include analysis of power costs, cost allocations, decoupling mechanisms, and sales forecasts. I have worked on power costs in the following OPUC dockets: IPC UE 301, IPC UE 305, PAC UE 307, and PGE UE 308. From September 2014 to September 2015 I was employed by Regulatory Affairs Public Advocacy group of the Alaska Department of Law. From 2008 to 2012 I was employed by the University of Oregon as an instructor. I taught undergraduate level courses in Microeconomics, Urban Economics, and Public Economics.

CASE: UM 1953
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Response Testimony

July 18, 2018

July 6, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Karla Wenzel
Manager, Pricing & Tariffs

PORTLAND GENERAL ELECTRIC
UM 1953
PGE Response to OPUC Data Request No. 004
Dated June 22, 2018

Request:

Does PGE believe that the current QF capacity rates represent PGE's current avoided cost?

Response:

PGE acknowledges that the approved Schedule 201 avoided cost for purposes of PURPA is a collaborative process that is reviewed by the Commission and stakeholders, and represents the approved methodology for valuing capacity in Oregon.

July 6, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Karla Wenzel
Manager, Pricing & Tariffs

PORTLAND GENERAL ELECTRIC
UM 1953
PGE Response to OPUC Data Request No. 006
Dated June 22, 2018

Request:

Has PGE lobbied or supported any lobbying related to qualified facilities? If yes, please identify all such efforts from January 1, 2013 to present.

Response:

PGE objects to this request on the grounds that it is overly broad. Without waiving this objection, PGE responds as follows:

PGE is a member of the Edison Electric Institute and other trade and industry groups that lobby on a number of issues. PGE does not control or direct the lobbying of these groups.

PGE has presented Attachment 006-A in 2018. PGE notes that lobbying expenses are not included in rates paid by customers.

Portland General Electric's Experience with PURPA

Portland General Electric (PGE) is committed to building a cleaner energy future for Oregon. PGE was among the first energy companies to advocate for climate legislation at the national level and we have a long history of helping to shape and support state and national policies that promote renewable energy, energy efficiency, smart grid and storage deployment, transportation electrification, and greenhouse gas emission reductions. Most recently, we were part of a broad coalition that worked to craft and enact Oregon's Clean Electricity and Coal Transition Plan, SB 1547 (2016). It sets a deadline for getting coal out of our resource mix and requires us to serve our customers with energy that is 50% renewable by 2040. At present, our generation mix is about 40% carbon-free. By 2040, assuming physical compliance with SB 1547, 70% of PGE's energy will be from carbon-free resources. PGE also signed onto The American Business Act on Climate Pledge, and recently joined more than 1,200 governors, mayors, businesses, and colleges and universities from across the U.S. in declaring their intent to continue to ensure the U.S. remains a global leader in reducing carbon emissions.

PURPA's mandatory purchasing obligation significantly and unnecessarily increases the costs of decarbonizing the electricity sector for PGE's customers because PURPA contracts lack the planning and cost scrutiny undertaken for other resource decisions. PURPA should be modernized to achieve the law's intent in today's renewable energy economy while protecting utility customers from excessive costs.

PURPA Background: The Public Utility Regulatory Policies Act of 1978 (PURPA) was enacted to increase energy independence at a time when an oil dependent US was in the midst of an energy crisis. PURPA's Section 210 created a mandatory purchase obligation for utilities to buy power from "qualifying facilities," including cogeneration plants and renewable power producers smaller than 80 MW.

Much has changed in the decades since the Act's passage – the structure of the electric sector, technological advances enabling increased renewables, and broad policy support for renewable development. Since PURPA's passage, a number of state and federal laws to promote renewable power have been enacted, including tax incentives and renewable portfolio standards, which have resulted in the development of a robust renewable energy industry and significant renewable power growth. Nearly forty years after PURPA's enactment, we face the need to significantly reduce the carbon emissions from the nation's energy use at the lowest possible cost to customers.

The Issues:

- PURPA's mandatory purchase requirement forces PGE to contract for resources regardless of whether PGE needs them or not.
- PURPA contracts establish long-term price contracts for power, potentially exposing customers to paying above-market costs.
  - Standard PURPA contracts in Oregon last twenty years, and require our customers to pay a fixed price for that power for the first 15 years, despite the expectation that renewable power prices will continue to drop in future years.
  - As implemented today, PURPA's mandatory purchase obligation could require our customers to pay an estimated $86 million more a year in their power rates by 2022, when *currently contracted* PURPA power will be on line, and the rate impact is expected to increase as additional PURPA power gets on the system.
- PURPA contracts occur outside of utilities' Integrated Resource Planning (IRP) process, and therefore lack the planning and cost scrutiny undertaken for other resource decisions.

  - PGE uses an IRP process to meet our customers' needs for power using least-cost, least-risk principles and a combination of supply- and demand-side measures. IRPs are overseen by the Oregon Public Utility Commission (PUC) and result in a competitive resource procurement process – an open Request For Proposal (RFP) – for any new resources that need to be acquired.
  - PURPA contracts are not competitively bid, nor are they limited to the size of the resource need identified in the IRP. The cost of PURPA contracts is not determined by the market, but according to the PUC's determination of PGE's "avoided cost," the cost theoretically avoided by purchasing this power elsewhere. Avoided cost determinations, however, significantly over-estimate the long-term price of power, particularly as the cost of renewables continues to drop dramatically over time.
- The price of electricity is a fundamental driver of the national and regional economy. PURPA's mandatory purchase obligation artificially inflates this price. Congress should amend PURPA's mandatory purchase obligation to keep costs low as we decarbonize the nation's grid.

<u>What It Means for PGE:</u> As of May 17, 2018, PGE has 1,689 MW of PURPA contracts either online, under contract or in process. In 2021, when all these resources are anticipated to come online, PURPA generation could represent more than 50% of PGE's forecast average load. Solar represents 1,380 MW, or 82% of the contracted and proposed PURPA projects.

Large, multinational developers are able to "game" PURPA's regulations by breaking up larger projects into smaller increments, forcing PGE's customers to pay above-market prices for energy. Solar developers are taking advantage of the rapidly declining cost for solar panels while locking PGE's customers into paying ever-greater above-market costs for energy and capacity. The majority of PGE's PURPA solar development comes from large, sophisticated developers that are using PURPA's outdated statutes to their advantage. Key examples include:

- One large, multinational developer has proposed five 10-MW projects for a total of 50MW. Projects 10 MW and under are not required to negotiate terms and conditions, and are instead granted very favorable standard contract terms intended to help small developers.
- Another developer has proposed twenty-six separate projects for a total of 68 MW.

<u>Impact to PGE's Retail Customers:</u>
PGE's preliminary estimate indicates that even if only the approximately 500 MW of currently contracted projects come to fruition, PGE's customers would see <u>a 5% rate increase in 2022</u> when these projects come on line, costing customers approximate <u>$86 million each year</u>.
If PGE is required to purchase the output from all PURPA requests to date, <u>PGE customers could experience price increases exceeding 15%.</u>

PGE's customers would save on these unneeded costs if PGE were able to use competitive procurement – and procure only the resources needed to meet customers' demand. Costs are likely to rise as more contracts get signed. PGE could also face reliability risk as many PURPA generators are not subject to the same reliability requirements as other renewable generators.

Solution: Protect utility customers by amending PURPA's Mandatory Purchase Obligation and Supporting FERC efforts to reform PURPA.

July 6, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Karla Wenzel
Manager, Pricing & Tariffs

PORTLAND GENERAL ELECTRIC
UM 1953
PGE Response to OPUC Data Request No. 015
Dated June 22, 2018

Request:

Continuing the example from DR 12,

a. **Please provide illustrative workpapers demonstrating how cost of service customers are insulated from costs and risks of this program in the event that the green tariff load subsequently drops to 0 MWa.**
b. **Please explain how PGE will insulate customers from the required rate of return on rate base impacts of shareholder baring the risk of under-subscription to green resources.**

Please explain what PGE will do with excess energy and RECs in the event of under-subscription.

Response:

a. Please reference Attachment 014-A.
b. As stated in PGE/200, Sims-Tinker/16 beginning at 21: "In the event that a portion of the project is unsubscribed, PGE shareholders will bear the difference between the PPA price and the energy/capacity credits."

July 6, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Karla Wenzel
Manager, Pricing & Tariffs

PORTLAND GENERAL ELECTRIC
UM 1953
PGE Response to OPUC Data Request No. 016
Dated June 22, 2018

Request:

Please refer to PGE/200, Sims – Tinker/15.

a. **Please explain how the risk premium will be calculated and provide an illustrative example.**
b. **Please explain how PGE will account for the risk premium in rates.**
c. **Please explain how PGE will calculate realized risk, and identify when the realized risk has exceeded the risk premium.**

Please explain what will occur to the risk premium if the realized risk is below the risk premium.

Response:

a. The risk premium will be dependent on subscriber level, current market conditions, PPA length and characteristics, and term length of subscriptions. PGE is unable to forecast the risk premium at this time, and will do so in individual contracts between PGE and subscribers – which will be filed as a compliance filing for Commission review.
b. There will be no risk premium included in rates. PGE's calculation of a risk premium is designed to insulate customers from subscriber turnover or other ancillary project risks.
c. PGE will calculate realized risk via program accounting. Realized risk will be applicable only to shareholders.