ORDER NO. 20-242

ENTERED Jul 30 2020

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2060

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Update to Schedule 201 - As-Available Rate.	ORDER

DISPOSITION: STAFF'S RECOMMENDATION ADOPTED

At its public meeting on July 28, 2020, the Public Utility Commission of Oregon adopted Staff's recommendation in this matter. The Staff Report with the recommendation is attached as Appendix A.

BY THE COMMISSION:

Nolan Moser
Chief Administrative Law Judge

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Circuit Court for Marion County in compliance with ORS 183.484.

ITEM NO. RA1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: July 28, 2020

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** **July 29, 2020**

DATE: July 20, 2020

TO: Public Utility Commission

FROM: Natascha Smith

THROUGH: Bryan Conway, Michael Dougherty, JP Batmale, and Kimberly Herb **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 2060)
Update to Schedule 201-As-Available Rate.

STAFF RECOMMENDATION:

Approve Portland General Electric Company's (PGE or Company) update to Schedule 201 and 202, subject to Staff-proposed modifications.

DISCUSSION:

Issue

Whether the Oregon Public Utility Commission (OPUC or Commission) should approve PGE's updates to PGE's PURPA Schedules 201 and 202.

Applicable Law

18 C.F.R. §292.304(d)(1) Pursuant to FERC regulations, where the utility purchases as available energy, "the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery."

OAR 860-029-0085(5) provides that the Commission may consider out-of-cycle updates to PURPA avoided cost rates to reflect significant changes in circumstances at any time. Out-of-cycle updates are subject to review and approval by the Commission and will become effective within 90 days after filing.

OAR 860-029-0040(3) dictates that the rate for non–firm energy must be based on the purchasing public utility's non-firm energy avoided cost in effect when the energy is delivered.

In Order No. 19-392, the Commission specified that the rate for unsubscribed energy in the Community Solar Program (CSP) would be the utilities' as-available rates for PURPA contracts.

Order No. 07-360 provided direction for setting an as-available rate, stating "as-available [Qualifying Facilities (QF)] shall receive day-ahead non-firm market index rates for on-peak and off-peak energy based on the appropriate market index and market hub(s)."

Analysis

Background

On February 28, 2020, PGE filed PGE's Update to Schedules 201 and 202 to establish an as-available rate (Update). PGE seeks an effective date of July 29, 2020. PGE made its filing in part as a response to the requirement in OAR 860-088-0140(1)(a) for electric companies to purchase unsubscribed generation from a Community Solar Project "on an 'as-available' basis," and in alignment with PGE Advice No. 20-04.[1]

Though PGE previously entered into contracts for the purchase of non-firm energy under PURPA, PGE's contracts ended in 2014 and the Company has not had an established as-available rate since that time.[2] PGE's update proposes a new methodology for determining the as-available rate. Specifically, PGE previously set quarterly as-available prices using forecasted forward market curves for the firm Mid-Columbia (Mid-C) market whereas the update proposes to set the as-available rate by discounting firm day-ahead Mid-C prices. PGE Asserts that the Company's revised proposal more accurately reflects PGE's actual as-available rate than its former approach, used in UM 1561.[3]

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[1] OAR 860-088-0140(1)(a) "Upon request, an electric company must enter into a 20-year power purchase agreement with a pre-certified project to purchase the project's unsold and unsubscribed generation on an 'as available' basis subject to the requirements of the Public Utility Regulatory Policy Act (PURPA) and ORS 758.505, et. seq;" *see*, Docket No. ADV 1095/Advice No. 20-04, Initial Utility Filing (Feb 18, 2020).
[2] *See* generally Docket No. UM 1561, PGE's Quarterly Non-Firm Avoided Cost Fillings (closed May 12, 2014).
[3] *See* Portland General Electric's Revised Request to Update Schedule 201, at page 5, Docket No. UM 2060, July 8, 2020.

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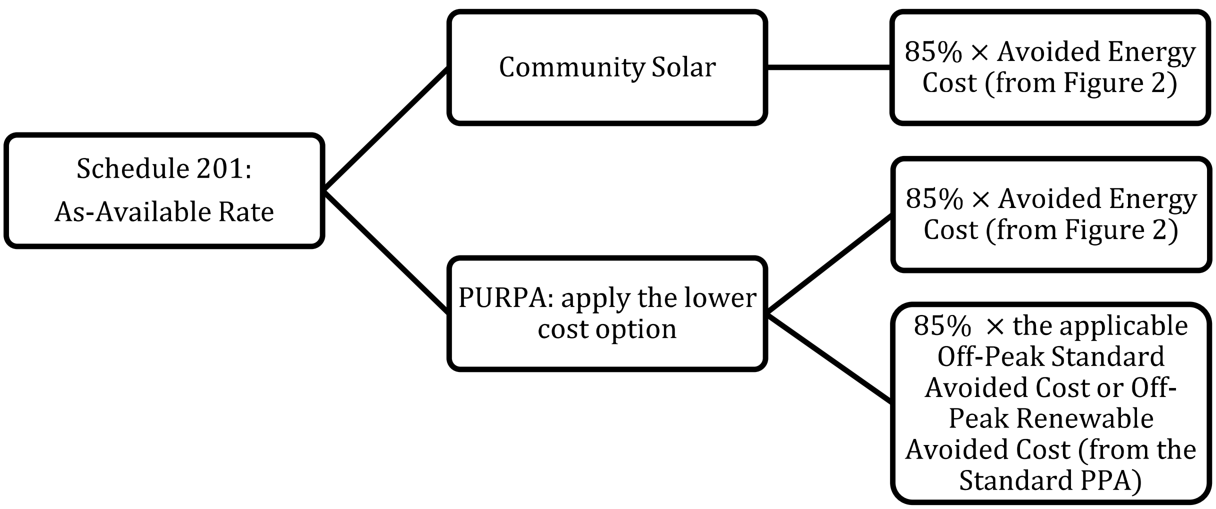
Staff notes that PGE's filling also includes format and definition changes to Schedule 201, made for clarity, as well as inclusion of a reference to the as-available rate in Schedule 202. Staff supports these changes.

Calculation of the As-Available Rate
PGE's filling includes multiple scenarios for the as-available rate as summarized in the Figure below.

Figure 1: Summary of PGE's As-Available Rate



In the context of unsubscribed power payments made as part of the Community Solar Program, PGE would set the as available rate as 85 percent of the avoided cost of energy. PGE defines avoided non-firm energy cost as "82.4% of the monthly arithmetic average of each day's ICE Mid-C Physical Peak (bilateral) and Mid-C Physical Off-Peak (bilateral) average index prices."[4] The Intercontinental Exchange (ICE) Mid-C Physical Peak and Mid-C Physical Off-Peak indices are representative of the market for firm energy transactions at the Mid-C trading hub.

PGE explains that it is necessary to discount the firm index price when setting the As-Available Rate because QF energy provided on a non-firm, as-available basis lacks the qualities and characteristics assumed in firm prices.[5] PGE would multiply the firm price by 82.4 percent, as shown below, to approximate non-firm pricing. Using PGE's methodology each day's index prices reflect the relative proportions of peak hours and

[4] *Id.*, Attachment A, at page 201-23.
[5] *Id.*, at page 3.

off-peak hours in the month. PGE proposes to further reduce the avoided cost of energy by multiplying the avoided non-firm energy cost by 85 percent to account for "transactional and transmission costs."[6]

Figure 2: Avoided Non-Firm Energy Cost Equation

$$.824 * \left(\sum_{X=1}^{n} \{(\text{ICE Mid-C Physical Peak (bilateral) Avg}_X * \text{applicable peak index hours for day}) + (\text{ICE Mid-C Physical Off-Peak (bilateral) Avg}_X * \text{applicable off-peak index hours for day})\} / (n*24)\right)$$

where n = number of days in the month

In the PURPA context, PGE proposes a slightly different approach. Instead of basing the as available rate primarily on the Mid-C market price, as proposed in the Community Solar Context, PGE would pay the lower of the avoided non-firm energy cost or the applicable standard off-peak rate:[7]

> The As-Available Rate is equal to eighty-five percent (85%) of the lower of 1) the Avoided [Non-Firm] Energy Cost, or 2) the applicable Off-Peak Standard Avoided Cost or Off-Peak Renewable Avoided Cost pursuant to the Schedule in effect on the Effective Date (as defined in the Standard PPA) of the applicable PPA. The Company will purchase As-Available Energy at the As-Available Rate.

This means that the as-available rates can never exceeded the applicable off-peak avoided cost rate, regardless of the prices reflected in the Mid-C market.

Compliance with Avoided Cost Guidance

As part of a multi-year investigation into Public Utility Regulatory Policies Act (PURPA) policies and procedures, the Commission issued Order No. 07-360, which interpreted FERC's rule that an as-available rate should reflect a Utility's "avoided costs calculated at the time of delivery."[8] FERC defines a utility's full avoided costs as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the

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[6] *Id.*, at page 4.
[7] PGE's filling refers to avoided non-firm energy costs as "avoided energy costs." Staff chose to include the modifier non-firm for clarity and to help distinguish it from standard or renewable avoided costs.
[8] Order No. 07-360, Docket No. UM 1129, at page 14, Aug. 20, 2007.

purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[9]

Order No. 07-360 specifies that for QFs providing energy on an as-available basis, avoided cost rates should be based on day-ahead market index prices for non-firm purchases.[10] The formerly available Dow Jones index provided non-firm prices on a day-ahead basis for Mid-C, but the Dow Jones index was discontinued in 2013. Since day-ahead non-firm prices are no longer available, PGE proposes to discount Mid-C firm energy prices, multiplying firm energy prices by 82.4 percent to reflect the value of non-firm energy deliveries.

The Commission has approved the use of discounted firm power costs as a substitute for non-firm power for other Oregon utilities. The as-available rates used by Pacific Power and Idaho Power are both based on market prices for firm-energy delivery as described below. Staff has previously expressed support for PGE using a methodology similar to that used by PacifiCorp and Idaho Power to set the as-available rate.

Figure 3: As-Available Rate Methodologies in Oregon

Company	Methodology
PAC	Pacific Power shall pay Seller 93 percent of a blended market index price for day-ahead *firm* energy at Mid-Columbia, California Oregon Border (COB), Four Corners and Palo Verde market indices as reported by the Intercontinental Exchange (ICE), for the On-Peak and Off-Peak periods.[11]
IPC	82.4 percent of the monthly arithmetic average of the Intercontinental Exchange (ICE) daily *firm* Mid-C Peak Average and Mid-C Off-Peak Average reported prices.[12]

Since PGE proposes different scenarios for setting the as-available rate, Staff will address both scenarios compliance with the Commission's guidance individually.

As-Available Rate for Community Solar

PGE's proposed as-available rate in the context of community solar is similar to the Commission approved methodology used by Idaho Power. The proposal to use the avoided cost of energy as the as-available rate is consistent with the Commission's

[9] 38 18 C.F.R. § 292.101(b)(6).
[10] Order No. 07-360, Docket No. UM 1129, at page 49, Aug. 20, 2007.
[11] *See* Docket No. UM 1793, Standard Avoided Cost Purchases from Eligible Qualifying Facilities, updated May 2020.
[12] *See* Docket No. UM 1730, Idaho Power Update to Avoided Cost Rates, Schedule 85, updated May 2020.

guidance in Order No. 07-360, that as-available rates should be based on day-ahead non-firm market index rates for on-peak and off-peak energy based on the appropriate market index and market hub(s).

Staff agrees that the Mid-C market is the appropriate market hub since it is PGE's primary market hub, and the trading hub nearest PGE's system.[13] Further PGE's proposal appropriately uses day ahead market index rates for peak and off-peak energy. Though non-firm market index prices are unavailable, Staff believes that Commission's prior approval of discounting firm energy prices to approximate the value of non-firm energy demonstrates that this approach is reasonable.

In Order No. 19-392, the Commission specified that the rate for unsubscribed energy in the Community Solar Program (CSP) would be the same as utilities' as-available rates for PURPA contracts. This order requires PGE to set an as-available rate for PURPA and does not permit PGE to use a rate different from the PURPA as-available rate for Community Solar. Here, PGE's proposes to use a different, though similar, methodology for Community Solar than that proposed for PURPA. Thus, PGE's proposal does not comply with Order No 19-392.

Additionally, PGE provides little explanation and no information to justify the further discount of the avoided non-firm energy cost. The Commission's guidance for as-available rates does not include any discounting for transmission or scheduling; rather it specifies that the as available rate should reflect an appropriate market rate for non-firm energy. Notably, neither Pacific Power nor Idaho Power discounts their as-available rate to account for scheduling and transmission.[14] It is unclear why PGE believes it is appropriate for them to do so or why the 85 percent multiplier is the appropriate figure.

As-Available Rate for PURPA
For PURPA, PGE proposes to use either the non-firm energy avoided cost or the applicable (standard or renewable) off-peak avoided cost, whichever is less. PGE provides no rationale supporting this proposed methodology. PGE's proposal is troubling in three respects.

First, the use of either standard or renewable avoided costs in place of non-firm energy avoided costs conflicts with the requirement set in OAR 860-029-0040(3).
OAR 860-029-0040(3) dictates that the rate for non–firm energy must be based on the purchasing public utility's *non-firm energy avoided cost* in effect when the energy is

[13] *See* Portland General Electric's Revised Request to Update Schedule 201, at page 3, Docket No. UM 2060, July 8, 2020.
[14] *See* Docket No. 1730, Idaho Power Update to Schedule 85, last updated May 2020; *see also* Docket No. UM 1739, Pacific Power Update to Schedule 37, last updated July 2020.

delivered. PGE's approach inappropriately caps the non-firm energy avoided cost using avoided cost for firm energy.

Second, the proposed methodology seems to ignore FERC's statement that as-available rates should be based on the purchasing utility's avoided costs calculated at the time of delivery. Standard avoided costs, as articulated in PGE's Schedule 201, sets standard and renewable avoided cost rates for future years. For example, the standard avoided costs listed in this filing set standard and renewable off-peak avoided cost rates from 2020-2045. Potentially subjecting non-firm energy deliveries to rates set 25 years prior is inconsistent with an as-available rate reflecting avoided costs at the time of energy delivery. This capping could result in a substantial decrease in revenue for a QF receiving the as-available rate as demonstrated in Confidential Attachment B. Staff believes that this discrepancy could lead to the as-available rate being challenged by the QF community.

Lastly, PGE's filling raises the same concerns around discounting the rate for scheduling and transmission as discussed in the Community Solar context above.

Staff Recommendation on Schedule 201 Filling

Staff recognizes that it is important to have an as-available rate in the near term to support Community Solar, because the as-available rate will apply to the unsubscribed portion of energy deliveries under the CSP. This is PGE's second attempt at filling an as-available rate. PGE's first filling was withdrawn due to potential legal challenges, and this filling raises similar concerns.

Staff has reviewed the Schedule 201 language and concludes that the document contains variations from well-established methodologies previously approved by the Commission. Staff acknowledges that its recommended changes to the Commission are not an exhaustive list of all concerns held by stakeholders, but believes that Staff's proposed modifications are required to ensure a viable as-available rate. Staff's proposed changes are outlined below and included in a redlined version of Schedule 201, included as Attachment A.

1. <u>Harmonize the as-available rate used in the Community Solar and PURPA contexts</u>. By using a singular methodology, the company can achieve compliance with the Commission's order to use the PURPA as-available rate as the unsubscribed power rate in the Community Solar Program
2. <u>Eliminate the use of the applicable off-peak avoided cost rate</u>. Using firm-power off-peak avoided costs conflicts with FERC and Commission guidance for setting as-available rates. Eliminating this portion of the Schedule 201 will bring the filling into compliance.

3. Eliminate the discount for scheduling and transmission. The Commission has stated that the as-available rate should reflect an appropriate market rate for non-firm power. Discounting for transmission and scheduling does not reflect market prices and seems inappropriate for on-system generators. Eliminating this portion of the Schedule 201 will bring the filling into compliance.

Conclusion

In summary, Staff recommends that the Commission direct PGE to make Staff's suggested modifications changes to their Schedule 201 and re-file with the Commission.

PROPOSED COMMISSION MOTION:

Approve Portland General Electric Schedules 201 and 202, subject to the direction to re-file the portions of the schedule 201 by August 11, 2020, that incorporate Staff proposed modifications.

UM 2060 PGE Update to Schedule 201

SCHEDULE 201
QUALIFYING FACILITY 10 MW or LESS
AVOIDED COST POWER PURCHASE INFORMATION

PURPOSE

To provide information about Standard Avoided Costs and Renewable Avoided Costs, Standard Power Purchase Agreements (PPA) and Negotiated PPAs, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company with nameplate capacity of 10,000 kW (10MW) or less.

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard PPA.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard PPA, a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security deemed sufficient by the Company as set forth in the Standard PPA.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

PPA

In accordance with terms set forth in this schedule and the Commission's Rules as applicable, the Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a PPA with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF and memorialized in the PPA.

A QF with a nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard PPA.

SCHEDULE 201 (Continued)

PPA (Continued)

Any Seller may elect to negotiate a PPA with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on either the filed Standard Avoided Costs or Renewable Avoided Costs in effect at that time.

STANDARD PPA (Nameplate capacity of 10 MW or less)

A Seller choosing a Standard PPA will complete all informational and price option selection requirements in the applicable Standard PPA and submit the executed Agreement to the Company prior to service under this schedule. The Standard PPA is available at www.portlandgeneral.com. The available Standard PPAs are:

- Standard In-System Non-Variable Power Purchase Agreement
- Standard Off-System Non-Variable Power Purchase Agreement
- Standard In-System Variable Power Purchase Agreement
- Standard Off-System Variable Power Purchase Agreement
- Standard Renewable In-System Non-Variable Power Purchase Agreement
- Standard Renewable Off-System Non-Variable Power Purchase Agreement
- Standard Renewable In-System Variable Power Purchase Agreement
- Standard Renewable Off-System Variable Power Purchase Agreement

The Standard PPAs applicable to variable resources are available only to QFs utilizing wind, solar or run of river hydro as the primary motive force.

GUIDELINES FOR 10 MW OR LESS FACILITIES ELECTING STANDARD PPA

To execute the Standard PPA the Seller must complete all of the general project information requested in the applicable Standard PPA.

When all information required in the Standard PPA has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard PPA.

The Seller may request in writing that the Company prepare a final draft Standard PPA. The Company will respond to this request within 15 business days. In connection with such request, the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard PPA.

When both parties are in full agreement as to all terms and conditions of the draft Standard PPA, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, an executed copy will be returned to the Seller. Prices and other terms and conditions in the PPA will not be final and binding until the Standard PPA has been executed by both parties.

SCHEDULE 201 (Continued)

OFF-SYSTEM PPA

A Seller with a facility that interconnects with an electric system other than the Company's electric system may enter into a PPA with the Company after following the applicable Standard or Negotiated PPA guidelines and making the arrangements necessary for transmission of power to the Company's system.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase prices are based on either the Company's Standard Avoided Costs or Renewable Avoided Costs in effect at the time the agreement is executed. Avoided Costs are defined in 18 CFR 292.101(6) as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

Monthly On-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1a, 2a, and 3a and Renewable Avoided Costs as listed in Tables 4a, 5a, and 6a. Monthly Off-Peak prices are included in both the Standard Avoided Costs as listed in Tables 1b, 2b, and 3b and Renewable Avoided Costs as listed in Tables 4b, 5b, and 6b.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Standard Avoided Costs are based on forward market price estimates through the Resource Sufficiency Period, the period of time during which the Company's Standard Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the Resource Deficiency Period, the Standard Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 94.01% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs.

Renewable Avoided Costs are based on forward market price estimates through the Renewable Resource Sufficiency Period, the period of time during which the Company's Renewable Avoided Costs are associated with incremental purchases of energy and capacity from the market. For the Renewable Resource Deficiency Period, the Renewable Avoided Costs reflect the fully allocated costs of a wind plant including capital costs.

SCHEDULE 201 (Continued)

PRICING FOR STANDARD PPA

Pricing represents the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard PPA up to the nameplate rating of the QF in any hour.

ELIGIBILITY REQUIREMENTS TO RECEIVE THE STANDARD FIXED PRICE OPTION OR THE RENEWABLE FIXED PRICE OPTION

The Standard PPA pricing will be based on either the Standard or Renewable Avoided Costs in effect at the time the agreement is executed. A QF will be eligible to receive either the Standard Fixed Price Option or the Renewable Fixed Price Option described below only if the nameplate capacity of the QF does not exceed 3 MW for solar QF projects or 10 MW for all other types of QF projects. A QF that does not meet these eligibility requirements must negotiate prices pursuant to the terms of Schedule 202. Solar QF projects with nameplate capacity that exceed 3 MW but do not exceed 10 MW are eligible for a Standard PPA containing negotiated prices under Schedule 202. Eligibility for the Standard Fixed Price Option or the Renewable Fixed Price Option may also be affected by the Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Fixed Price Option or the Renewable Fixed Price Option Under the Standard PPA stated below.

Except for As-Available Energy, the Company will pay the Seller either the On-Peak Standard Avoided Cost pursuant to Tables 1a, 2a, or 3a or the On-Peak Renewable Avoided Costs pursuant to Tables 4a, 5a, or 6a for Net Output delivered in the On-Peak Period. Except for As-Available Energy, the Company will pay the Seller either the Off-Peak Standard Avoided Cost pursuant to Tables 1b, 2b, or 3b or the Off-Peak Renewable Avoided Costs pursuant to Tables 4b, 5b, or 6b for Net Output delivered in the Off-Peak Period. The Company will pay the Seller the As-Available Rate for all As-Available Energy delivered during the PPA Term.

1) **Standard Fixed Price Option**

The Standard Fixed Price Option is based on Standard Avoided Costs including forecasted natural gas prices. It is available to all QFs that meet the eligibility requirements identified above.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Standard Avoided Costs in Tables 1a and 1b, 2a and 2b, or 3a and 3b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

Prices paid to the Seller under the Standard Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both the Base Load QF resources (Tables 1a and 1b) and the avoided proxy resource, the basis used to determine Standard Avoided Costs for the Standard Fixed Price Option, are assumed to have a capacity contribution to peak of 100%. The capacity contribution for Wind QF resources (Tables 2a and 2b) is assumed to be 28.57%. The capacity contribution for Solar QF resources (Tables 3a and 3b) is assumed to be 15.78%.

Prices paid to the Seller under the Standard Fixed Price Option for Wind QFs (Tables 2a and 2b) include a reduction for the wind integration costs in Table 7. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 2a and 2b, for a net-zero effect.

Prices paid to the Seller under the Standard Fixed Price Option for Solar QFs (Tables 3a and 3b) include a reduction for the solar integration costs in Table 7. However, if the Solar QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the solar integration charges in Table 7, in addition to the prices listed in Tables 3a and 3b, for a net-zero effect.

Sellers with terms exceeding 15 years from the commercial operation date will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15 years after the commercial operation date selected by the Seller and memorialized in the PPA.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 1a Avoided Costs Fixed Price Option for Base Load QF On-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2020	23.73	23.47	18.89	16.59	14.55	19.40	42.59	53.29	36.47	29.08	30.10	42.59
2021	41.32	38.29	28.90	19.56	17.79	22.39	53.86	64.43	45.21	33.93	34.84	44.48
2022	44.63	38.76	30.62	25.68	23.21	27.98	48.39	57.17	41.77	34.23	35.20	44.78
2023	43.46	38.76	30.62	25.68	23.21	31.43	46.17	52.44	40.72	34.56	35.06	40.59
2024	45.08	41.97	35.02	30.60	29.48	33.61	49.42	56.15	43.58	36.97	37.51	43.44
2025	43.98	44.05	44.12	43.40	43.47	43.55	43.63	43.70	43.78	43.86	44.88	44.96
2026	47.31	47.41	47.50	46.60	46.69	46.78	46.87	46.97	47.06	47.25	48.32	48.41
2027	49.50	49.60	49.36	48.37	48.46	48.34	48.43	48.53	48.63	48.72	46.42	46.50
2028	47.44	46.64	46.62	45.69	45.77	45.84	45.92	46.00	46.08	46.16	47.27	47.36
2029	48.43	48.51	47.81	46.85	46.93	47.02	47.10	47.18	47.27	47.38	48.49	48.57
2030	49.67	49.77	49.76	48.76	48.85	48.94	49.03	49.12	49.21	49.30	50.50	50.59
2031	51.75	51.85	51.94	50.87	50.97	51.07	51.16	51.26	51.36	51.49	52.86	52.97
2032	53.99	54.10	54.20	53.11	53.22	53.33	53.43	53.54	53.65	53.79	55.12	55.24
2033	56.69	56.81	55.65	54.53	54.64	54.75	54.86	54.98	55.09	55.25	56.57	56.68
2034	58.05	58.17	56.80	55.66	55.77	55.89	56.00	56.11	56.23	56.37	57.76	57.88
2035	59.10	59.22	58.63	57.38	57.49	57.61	57.73	57.85	57.97	58.25	59.54	59.66
2036	60.89	61.03	59.84	58.64	58.75	58.88	59.00	59.12	59.25	59.55	60.85	60.98
2037	62.52	62.65	62.58	61.38	61.51	61.64	62.16	62.33	62.47	64.07	66.20	66.35
2038	67.92	68.08	66.37	65.04	65.18	65.33	65.48	65.63	65.79	67.54	69.82	69.99
2039	71.68	71.86	71.72	70.27	70.44	70.61	70.79	70.96	71.14	72.50	74.32	74.51
2040	77.27	77.47	76.20	74.68	74.86	75.06	75.24	75.44	75.63	76.70	78.60	78.80
2041	78.87	79.07	77.78	76.23	76.41	76.61	76.80	77.00	77.20	78.29	80.23	80.43
2042	80.48	80.69	79.38	77.79	77.98	78.18	78.37	78.58	78.78	79.89	81.87	82.08
2043	82.13	82.35	81.00	79.38	79.58	79.78	79.98	80.19	80.39	81.53	83.55	83.76
2044	83.70	83.92	82.54	80.89	81.09	81.30	81.50	81.71	81.92	83.08	85.14	85.36
2045	85.65	85.88	84.48	82.79	82.99	83.20	83.41	83.63	83.84	85.02	87.13	87.35

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 1b Avoided Costs Fixed Price Option for Base Load QF Off-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2020	18.89	18.89	15.32	11.50	6.65	8.95	22.45	28.06	27.55	25.51	25.51	35.45
2021	33.16	30.67	24.27	14.37	10.89	12.46	26.59	31.81	29.62	27.92	28.80	35.12
2022	36.87	30.01	25.55	20.02	17.84	18.59	27.15	31.45	30.11	28.01	28.52	31.94
2023	33.93	30.30	25.79	20.20	18.00	18.76	27.41	31.75	30.39	28.28	28.79	32.25
2024	37.12	33.13	28.17	22.04	19.62	20.45	29.96	34.73	33.23	30.91	31.47	35.27
2025	18.86	18.94	19.01	18.28	18.36	18.44	18.51	18.59	18.67	18.75	19.77	19.85
2026	21.68	21.78	21.87	20.97	21.06	21.16	21.25	21.34	21.43	21.62	22.69	22.79
2027	23.35	23.45	23.21	22.21	22.31	22.19	22.28	22.38	22.47	22.57	20.27	20.35
2028	20.75	19.95	19.93	19.00	19.08	19.16	19.23	19.31	19.39	19.47	20.58	20.67
2029	21.19	21.28	20.57	19.62	19.70	19.78	19.86	19.95	20.03	20.14	21.25	21.34
2030	21.88	21.97	21.96	20.97	21.06	21.15	21.23	21.33	21.42	21.51	22.70	22.80
2031	23.38	23.48	23.57	22.51	22.61	22.71	22.80	22.90	23.00	23.13	24.50	24.60
2032	25.23	25.34	25.44	24.35	24.46	24.57	24.67	24.78	24.89	25.03	26.36	26.48
2033	27.15	27.27	26.11	25.00	25.10	25.22	25.33	25.44	25.55	25.71	27.03	27.15
2034	27.81	27.94	26.56	25.42	25.53	25.65	25.76	25.87	25.99	26.13	27.53	27.64
2035	28.34	28.46	27.87	26.62	26.73	26.85	26.97	27.09	27.21	27.49	28.78	28.90
2036	29.60	29.74	28.55	27.35	27.47	27.59	27.71	27.83	27.96	28.26	29.56	29.69
2037	30.49	30.62	30.55	29.35	29.48	29.61	30.12	30.30	30.44	32.04	34.16	34.32
2038	35.23	35.40	33.68	32.35	32.49	32.64	32.79	32.94	33.10	34.85	37.13	37.30
2039	38.32	38.50	38.36	36.91	37.08	37.25	37.43	37.61	37.79	39.14	40.96	41.15
2040	43.23	43.43	42.16	40.64	40.82	41.02	41.20	41.40	41.59	42.66	44.56	44.76
2041	44.13	44.34	43.04	41.49	41.68	41.87	42.06	42.26	42.46	43.55	45.49	45.70
2042	45.03	45.24	43.92	42.34	42.53	42.73	42.92	43.13	43.33	44.44	46.42	46.63
2043	45.96	46.17	44.82	43.20	43.40	43.60	43.80	44.01	44.22	45.35	47.37	47.59
2044	46.90	47.12	45.74	44.09	44.29	44.50	44.70	44.91	45.12	46.28	48.34	48.56
2045	47.86	48.08	46.68	44.99	45.20	45.41	45.62	45.83	46.05	47.23	49.33	49.56

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 2a
Avoided Costs
Fixed Price Option for Wind QF
On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2020	23.40	23.15	18.56	16.27	14.23	19.07	42.26	52.96	36.14	28.75	29.77	42.26
2021	40.99	37.96	28.56	19.23	17.45	22.06	53.53	64.10	44.88	33.59	34.51	44.15
2022	44.29	38.42	30.28	25.35	22.87	27.64	48.05	56.83	41.43	33.89	34.86	44.44
2023	43.11	38.42	30.28	25.34	22.86	31.08	45.82	52.10	40.38	34.21	34.71	40.24
2024	44.73	41.62	34.66	30.25	29.13	33.26	49.06	55.80	43.23	36.62	37.15	43.09
2025	35.38	35.46	35.53	34.80	34.87	34.95	35.03	35.11	35.19	35.26	36.28	36.36
2026	38.54	38.64	38.72	37.83	37.92	38.01	38.10	38.19	38.29	38.48	39.54	39.64
2027	40.55	40.65	40.40	39.41	39.51	39.39	39.48	39.58	39.67	39.77	37.47	37.55
2028	38.30	37.50	37.48	36.55	36.63	36.71	36.78	36.86	36.95	37.03	38.14	38.22
2029	39.10	39.19	38.48	37.53	37.61	37.69	37.77	37.86	37.94	38.05	39.16	39.25
2030	40.16	40.25	40.24	39.25	39.33	39.42	39.51	39.60	39.70	39.79	40.98	41.08
2031	42.04	42.14	42.23	41.16	41.26	41.36	41.45	41.55	41.65	41.78	43.15	43.26
2032	44.14	44.25	44.35	43.26	43.37	43.48	43.58	43.69	43.80	43.94	45.27	45.39
2033	46.57	46.69	45.54	44.42	44.53	44.64	44.75	44.86	44.98	45.14	46.45	46.57
2034	47.70	47.82	46.45	45.31	45.42	45.53	45.65	45.76	45.88	46.02	47.41	47.53
2035	48.57	48.69	48.10	46.85	46.96	47.08	47.20	47.32	47.44	47.72	49.00	49.13
2036	50.18	50.31	49.12	47.92	48.04	48.16	48.28	48.41	48.54	48.84	50.14	50.27
2037	51.55	51.69	51.61	50.41	50.54	50.68	51.19	51.36	51.50	53.10	55.23	55.38
2038	56.73	56.89	55.18	53.85	53.99	54.14	54.29	54.44	54.60	56.35	58.63	58.80
2039	60.26	60.44	60.30	58.85	59.02	59.19	59.37	59.54	59.72	61.08	62.90	63.09
2040	65.62	65.82	64.55	63.03	63.21	63.40	63.59	63.78	63.98	65.05	66.95	67.15
2041	66.98	67.18	65.89	64.33	64.52	64.72	64.91	65.11	65.31	66.39	68.33	68.54
2042	68.35	68.56	67.24	65.65	65.84	66.04	66.24	66.44	66.64	67.75	69.73	69.95
2043	69.75	69.96	68.62	67.00	67.19	67.40	67.59	67.80	68.01	69.14	71.16	71.38
2044	71.10	71.32	69.94	68.29	68.49	68.70	68.90	69.11	69.32	70.48	72.54	72.76
2045	72.72	72.94	71.54	69.85	70.05	70.27	70.47	70.69	70.91	72.09	74.19	74.41

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)

Standard Fixed Price Option (Continued)

TABLE 2b
Avoided Costs
Fixed Price Option for Wind QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2020	18.56	18.56	14.99	11.17	6.33	8.62	22.13	27.74	27.23	25.19	25.19	35.13
2021	32.83	30.33	23.94	14.04	10.56	12.13	26.26	31.48	29.29	27.59	28.47	34.79
2022	36.54	29.68	25.21	19.68	17.50	18.25	26.82	31.11	29.77	27.67	28.18	31.60
2023	33.58	29.96	25.44	19.86	17.66	18.41	27.07	31.41	30.05	27.93	28.45	31.90
2024	36.76	32.78	27.82	21.68	19.26	20.10	29.60	34.37	32.88	30.55	31.12	34.92
2025	18.50	18.58	18.65	17.92	18.00	18.08	18.15	18.23	18.31	18.39	19.41	19.49
2026	21.32	21.42	21.50	20.61	20.70	20.79	20.88	20.97	21.07	21.26	22.32	22.42
2027	22.97	23.08	22.83	21.84	21.93	21.81	21.91	22.00	22.10	22.20	19.89	19.97
2028	20.36	19.57	19.55	18.62	18.70	18.77	18.85	18.93	19.01	19.09	20.20	20.28
2029	20.80	20.89	20.18	19.23	19.31	19.39	19.47	19.56	19.64	19.75	20.86	20.95
2030	21.48	21.57	21.56	20.57	20.66	20.75	20.84	20.93	21.02	21.11	22.31	22.40
2031	22.98	23.08	23.17	22.11	22.20	22.30	22.40	22.50	22.60	22.72	24.10	24.20
2032	24.82	24.93	25.03	23.94	24.04	24.15	24.26	24.37	24.48	24.61	25.95	26.06
2033	26.73	26.85	25.69	24.57	24.68	24.79	24.90	25.02	25.13	25.29	26.61	26.72
2034	27.38	27.50	26.13	24.99	25.10	25.22	25.33	25.44	25.56	25.70	27.09	27.21
2035	27.90	28.02	27.43	26.18	26.29	26.41	26.53	26.65	26.77	27.05	28.34	28.46
2036	29.16	29.29	28.10	26.90	27.02	27.14	27.26	27.38	27.51	27.81	29.11	29.24
2037	30.03	30.16	30.09	28.89	29.02	29.15	29.67	29.84	29.98	31.58	33.70	33.86
2038	34.76	34.93	33.22	31.88	32.02	32.18	32.32	32.48	32.63	34.39	36.66	36.83
2039	37.84	38.02	37.88	36.43	36.60	36.78	36.95	37.13	37.31	38.66	40.48	40.67
2040	42.74	42.94	41.67	40.15	40.33	40.53	40.71	40.91	41.10	42.17	44.07	44.27
2041	43.63	43.84	42.54	40.99	41.18	41.37	41.56	41.76	41.96	43.05	44.99	45.20
2042	44.53	44.74	43.42	41.83	42.02	42.22	42.42	42.62	42.82	43.93	45.91	46.12
2043	45.44	45.65	44.31	42.69	42.88	43.09	43.28	43.49	43.70	44.83	46.85	47.07
2044	46.37	46.59	45.21	43.56	43.76	43.97	44.17	44.38	44.59	45.75	47.81	48.03
2045	47.32	47.54	46.14	44.45	44.66	44.87	45.08	45.29	45.51	46.69	48.79	49.02

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 3a Avoided Costs Fixed Price Option for Solar QF On-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2020	22.37	22.12	17.53	15.24	13.20	18.04	41.23	51.93	35.11	27.72	28.74	41.23
2021	39.94	36.91	27.51	18.18	16.40	21.01	52.48	63.04	43.83	32.54	33.46	43.10
2022	43.21	37.35	29.21	24.27	21.79	26.57	46.98	55.76	40.35	32.82	33.79	43.37
2023	42.02	37.32	29.18	24.24	21.76	29.99	44.73	51.00	39.28	33.12	33.62	39.15
2024	43.61	40.50	33.55	29.13	28.01	32.14	47.95	54.68	42.11	35.50	36.04	41.97
2025	27.47	27.54	27.61	26.89	26.96	27.04	27.11	27.19	27.27	27.35	28.37	28.45
2026	30.46	30.56	30.65	29.75	29.84	29.93	30.02	30.12	30.21	30.40	31.47	31.56
2027	32.31	32.41	32.16	31.17	31.27	31.14	31.24	31.34	31.43	31.53	29.22	29.31
2028	29.89	29.09	29.07	28.15	28.22	28.30	28.37	28.46	28.54	28.62	29.73	29.81
2029	30.52	30.61	29.90	28.95	29.03	29.11	29.19	29.28	29.36	29.47	30.58	30.67
2030	31.40	31.49	31.48	30.49	30.58	30.67	30.76	30.85	30.94	31.03	32.22	32.32
2031	33.10	33.20	33.29	32.23	32.32	32.42	32.52	32.62	32.72	32.84	34.22	34.32
2032	35.07	35.18	35.28	34.19	34.30	34.41	34.51	34.62	34.73	34.87	36.20	36.32
2033	37.27	37.39	36.23	35.11	35.22	35.33	35.44	35.56	35.67	35.83	37.15	37.26
2034	38.18	38.30	36.92	35.79	35.90	36.01	36.12	36.24	36.35	36.50	37.89	38.01
2035	38.87	39.00	38.41	37.15	37.27	37.39	37.51	37.63	37.75	38.03	39.31	39.44
2036	40.32	40.45	39.26	38.06	38.18	38.30	38.42	38.55	38.67	38.97	40.27	40.40
2037	41.46	41.59	41.52	40.32	40.45	40.58	41.10	41.27	41.41	43.01	45.14	45.29
2038	46.43	46.59	44.88	43.55	43.69	43.84	43.99	44.14	44.30	46.05	48.33	48.50
2039	49.75	49.93	49.79	48.33	48.50	48.68	48.85	49.03	49.21	50.57	52.39	52.58
2040	54.89	55.09	53.82	52.30	52.48	52.68	52.86	53.06	53.25	54.32	56.22	56.42
2041	56.03	56.23	54.94	53.39	53.57	53.77	53.96	54.16	54.36	55.45	57.39	57.59
2042	57.18	57.39	56.07	54.48	54.67	54.87	55.07	55.27	55.47	56.58	58.56	58.77
2043	58.35	58.56	57.22	55.60	55.79	56.00	56.20	56.40	56.61	57.74	59.76	59.98
2044	59.50	59.72	58.34	56.69	56.89	57.10	57.30	57.51	57.72	58.88	60.94	61.16
2045	60.81	61.04	59.63	57.95	58.15	58.36	58.57	58.79	59.00	60.18	62.29	62.51

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Standard Fixed Price Option (Continued)

TABLE 3b												
Avoided Costs												
Fixed Price Option for Solar QF												
Off-Peak Forecast ($/MWH)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2020	17.53	17.53	13.96	10.14	5.30	7.59	21.10	26.71	26.20	24.16	24.16	34.10
2021	31.78	29.28	22.89	12.99	9.51	11.07	25.21	30.43	28.24	26.54	27.42	33.74
2022	35.46	28.60	24.14	18.61	16.43	17.18	25.74	30.04	28.69	26.60	27.11	30.53
2023	32.49	28.86	24.35	18.76	16.56	17.32	25.97	30.31	28.95	26.84	27.35	30.81
2024	35.65	31.66	26.70	20.57	18.15	18.98	28.49	33.26	31.76	29.44	30.00	33.80
2025	17.36	17.44	17.51	16.78	16.86	16.94	17.01	17.09	17.17	17.25	18.27	18.35
2026	20.15	20.25	20.34	19.44	19.53	19.62	19.72	19.81	19.90	20.09	21.16	21.25
2027	21.79	21.89	21.64	20.65	20.75	20.62	20.72	20.81	20.91	21.01	18.70	18.79
2028	19.15	18.35	18.34	17.41	17.49	17.56	17.64	17.72	17.80	17.88	18.99	19.07
2029	19.56	19.65	18.94	17.99	18.07	18.15	18.24	18.32	18.40	18.52	19.63	19.71
2030	20.22	20.31	20.30	19.31	19.40	19.49	19.57	19.67	19.76	19.85	21.04	21.14
2031	21.69	21.79	21.88	20.82	20.91	21.01	21.11	21.21	21.31	21.44	22.81	22.91
2032	23.50	23.61	23.71	22.62	22.73	22.84	22.94	23.05	23.17	23.30	24.63	24.75
2033	25.39	25.51	24.35	23.23	23.34	23.45	23.56	23.67	23.79	23.95	25.27	25.38
2034	26.01	26.14	24.76	23.62	23.73	23.85	23.96	24.07	24.19	24.33	25.72	25.84
2035	26.50	26.63	26.03	24.78	24.90	25.02	25.13	25.25	25.38	25.65	26.94	27.06
2036	27.73	27.86	26.67	25.47	25.59	25.71	25.83	25.96	26.09	26.38	27.69	27.81
2037	28.57	28.71	28.64	27.43	27.56	27.70	28.21	28.38	28.52	30.12	32.25	32.40
2038	33.28	33.44	31.73	30.40	30.54	30.69	30.84	30.99	31.15	32.90	35.18	35.35
2039	36.33	36.51	36.37	34.92	35.09	35.26	35.43	35.61	35.79	37.15	38.97	39.16
2040	41.20	41.40	40.13	38.60	38.79	38.98	39.17	39.36	39.56	40.63	42.53	42.73
2041	42.06	42.26	40.97	39.41	39.60	39.80	39.99	40.19	40.39	41.47	43.41	43.62
2042	42.92	43.13	41.81	40.22	40.41	40.61	40.81	41.01	41.21	42.32	44.30	44.51
2043	43.80	44.01	42.66	41.04	41.24	41.44	41.64	41.85	42.06	43.19	45.21	45.43
2044	44.69	44.91	43.54	41.88	42.08	42.29	42.50	42.71	42.92	44.08	46.14	46.36
2045	45.61	45.83	44.43	42.74	42.95	43.16	43.37	43.58	43.80	44.98	47.08	47.31

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)

2) Renewable Fixed Price Option

The Renewable Fixed Price Option is based on Renewable Avoided Costs. It is available only to Renewable QFs that generate electricity from a renewable energy source that may be used by the Company to comply with the Oregon Renewable Portfolio Standard as set forth in ORS 469A.005 to 469A.210 and that satisfy the eligibility requirements identified above.

This option is available for a maximum term of 15 years. Prices will be as established at the time the Standard PPA is executed and will be equal to the Renewable Avoided Costs in Tables 4a and 4b, 5a and 5b, or 6a and 6b, depending on the type of QF, effective at execution. QFs using any resource type other than wind and solar are assumed to be Base Load QFs.

Sellers will retain all Environmental Attributes generated by the facility during the Renewable Resource Sufficiency Period. A Renewable QF choosing the Renewable Fixed Price Option must cede all RPS Attributes generated by the facility to the Company from the start of the Renewable Resource Deficiency Period through the remainder of the PPA term.

Prices paid to the Seller under the Renewable Fixed Price Option include adjustments for the capacity contribution of the QF resource type relative to that of the avoided proxy resource. Both Wind QF resources (Tables 5a and 5b) and the avoided proxy resource, the basis used to determine Renewable Avoided Costs for the Renewable Fixed Price Option, are assumed to have a capacity contribution to peak of 28.57%. The capacity contribution for Solar QF resources (Tables 6a and 6b) is assumed to be 15.78%. The capacity contribution for Base Load QF resources (Tables 4a and 4b) is assumed to be 100%.

The Renewable Avoided Costs during the Renewable Resource Deficiency Period reflect an increase for avoided wind integration costs, shown in Table 7.

Prices paid to the Seller under the Renewable Fixed Price Option for Wind QFs (Tables 5a and 5b) include a reduction for the wind integration costs in Table 7, which cancels out wind integration costs included in the Renewable Avoided Costs during the Renewable Resource Deficiency Period. However, if the Wind QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the wind integration charges in Table 7, in addition to the prices listed in Tables 5a and 5b.

Prices paid to the Seller under the Renewable Fixed Price Option for Solar QFs (Tables 6a and 6b) include a reduction for the Solar integration costs in Table 7. However, if the Solar QF is outside of PGE's Balancing Authority Area as contemplated in the Commission's Order No. 14-058, the Seller is paid the solar integration charges in Table 7, in addition to the prices listed in Tables 6a and 6b.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)

Renewable Fixed Price Option (Continued)

Sellers with terms exceeding 15 years from the commercial operation date will receive pricing equal to the Mid-C Index Price for all years up to five in excess of the initial 15 years following the commercial operation date selected by the Seller and memorialized in the PPA.

TABLE 4a

Renewable Avoided Costs

Renewable Fixed Price Option for Base Load QF

On-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2020	23.73	23.47	18.89	16.59	14.55	19.40	42.59	53.29	36.47	29.08	30.10	42.59
2021	41.32	38.29	28.90	19.56	17.79	22.39	53.86	64.43	45.21	33.93	34.84	44.48
2022	44.63	38.76	30.62	25.68	23.21	27.98	48.39	57.17	41.77	34.23	35.20	44.78
2023	43.46	38.76	30.62	25.68	23.21	31.43	46.17	52.44	40.72	34.56	35.06	40.59
2024	45.08	41.97	35.02	30.60	29.48	33.61	49.42	56.15	43.58	36.97	37.51	43.44
2025	76.34	72.81	64.90	59.88	58.61	63.31	81.27	88.92	74.63	67.12	67.73	74.47
2026	77.91	74.30	66.23	61.11	59.81	64.60	82.93	90.74	76.16	68.50	69.12	76.00
2027	79.50	75.82	67.59	62.36	61.03	65.93	84.63	92.60	77.72	69.90	70.54	77.55
2028	80.98	77.23	68.86	63.54	62.19	67.17	86.20	94.31	79.17	71.21	71.86	79.00
2029	82.79	78.96	70.39	64.94	63.56	68.65	88.13	96.43	80.94	72.79	73.45	80.76
2030	84.49	80.58	71.83	66.27	64.86	70.06	89.94	98.41	82.60	74.29	74.96	82.42
2031	86.22	82.23	73.30	67.63	66.19	71.50	91.78	100.42	84.29	75.81	76.50	84.11
2032	87.64	83.58	74.49	68.72	67.26	72.66	93.30	102.09	85.67	77.04	77.74	85.49
2033	89.79	85.63	76.33	70.43	68.93	74.46	95.58	104.58	87.78	78.95	79.66	87.59
2034	91.73	87.48	77.99	71.97	70.44	76.08	97.63	106.82	89.67	80.66	81.39	89.48
2035	93.51	89.17	79.49	73.35	71.78	77.54	99.54	108.91	91.41	82.21	82.96	91.21
2036	95.15	90.74	80.89	74.63	73.04	78.90	101.28	110.82	93.01	83.65	84.41	92.81
2037	97.38	92.87	82.78	76.38	74.76	80.75	103.66	113.41	95.19	85.62	86.39	94.99
2038	99.37	94.77	84.48	77.95	76.29	82.40	105.78	115.74	97.14	87.37	88.16	96.94
2039	101.41	96.71	86.21	79.54	77.85	84.09	107.95	118.11	99.13	89.16	89.97	98.92
2040	103.29	98.51	87.83	81.04	79.32	85.67	109.95	120.29	100.98	90.83	91.65	100.77
2041	105.60	100.71	89.78	82.84	81.07	87.57	112.41	123.00	103.24	92.85	93.69	103.02
2042	107.77	102.78	91.62	84.53	82.73	89.36	114.72	125.52	105.35	94.75	95.61	105.13
2043	109.98	104.88	93.49	86.26	84.43	91.20	117.07	128.09	107.51	96.69	97.57	107.28
2044	111.91	106.72	95.13	87.77	85.91	92.79	119.12	130.34	109.40	98.39	99.28	109.16
2045	114.65	109.34	97.49	89.96	88.04	95.09	122.03	133.51	112.08	100.82	101.73	111.84

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 4b
Renewable Avoided Costs
Renewable Fixed Price Option for Base Load QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2020	18.89	18.89	15.32	11.50	6.65	8.95	22.45	28.06	27.55	25.51	25.51	35.45
2021	33.16	30.67	24.27	14.37	10.89	12.46	26.59	31.81	29.62	27.92	28.80	35.12
2022	36.87	30.01	25.55	20.02	17.84	18.59	27.15	31.45	30.11	28.01	28.52	31.94
2023	33.93	30.30	25.79	20.20	18.00	18.76	27.41	31.75	30.39	28.28	28.79	32.25
2024	37.12	33.13	28.17	22.04	19.62	20.45	29.96	34.73	33.23	30.91	31.47	35.27
2025	42.18	37.65	32.01	25.04	22.29	23.24	34.04	39.46	37.76	35.12	35.76	40.08
2026	43.04	38.42	32.67	25.55	22.75	23.71	34.74	40.27	38.54	35.84	36.50	40.90
2027	43.92	39.21	33.34	26.08	23.21	24.20	35.45	41.09	39.33	36.57	37.24	41.74
2028	44.70	39.90	33.93	26.54	23.62	24.63	36.08	41.82	40.02	37.22	37.90	42.48
2029	45.74	40.83	34.72	27.16	24.17	25.20	36.92	42.79	40.95	38.09	38.78	43.47
2030	46.68	41.67	35.43	27.71	24.67	25.72	37.67	43.67	41.79	38.87	39.58	44.36
2031	47.63	42.52	36.15	28.28	25.18	26.24	38.44	44.57	42.65	39.66	40.39	45.27
2032	48.48	43.27	36.79	28.78	25.62	26.71	39.12	45.35	43.40	40.37	41.10	46.07
2033	49.60	44.28	37.65	29.45	26.22	27.33	40.03	46.41	44.42	41.31	42.06	47.14
2034	50.62	45.19	38.42	30.05	26.75	27.89	40.86	47.36	45.33	42.15	42.92	48.11
2035	51.66	46.11	39.21	30.67	27.30	28.46	41.69	48.33	46.25	43.02	43.80	49.09
2036	52.57	46.93	39.90	31.21	27.79	28.96	42.43	49.19	47.07	43.78	44.58	49.96
2037	53.80	48.02	40.83	31.94	28.43	29.64	43.42	50.33	48.17	44.80	45.62	51.12
2038	54.90	49.00	41.67	32.59	29.01	30.25	44.31	51.36	49.16	45.71	46.55	52.17
2039	56.02	50.01	42.52	33.26	29.61	30.87	45.22	52.42	50.16	46.65	47.50	53.24
2040	57.01	50.89	43.28	33.85	30.13	31.41	46.02	53.34	51.05	47.48	48.34	54.18
2041	58.34	52.08	44.28	34.64	30.83	32.14	47.09	54.58	52.24	48.58	49.47	55.44
2042	59.54	53.15	45.19	35.35	31.47	32.80	48.05	55.70	53.31	49.58	50.48	56.58
2043	60.76	54.23	46.12	36.07	32.11	33.47	49.04	56.84	54.40	50.59	51.52	57.74
2044	61.83	55.19	46.93	36.71	32.68	34.07	49.90	57.85	55.36	51.49	52.43	58.76
2045	63.27	56.48	48.03	37.56	33.44	34.86	51.07	59.20	56.65	52.69	53.65	60.13

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 5a Renewable Avoided Costs Renewable Fixed Price Option for Wind QF On-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2020	23.40	23.15	18.56	16.27	14.23	19.07	42.26	52.96	36.14	28.75	29.77	42.26
2021	40.99	37.96	28.56	19.23	17.45	22.06	53.53	64.10	44.88	33.59	34.51	44.15
2022	44.29	38.42	30.28	25.35	22.87	27.64	48.05	56.83	41.43	33.89	34.86	44.44
2023	43.11	38.42	30.28	25.34	22.86	31.08	45.82	52.10	40.38	34.21	34.71	40.24
2024	44.73	41.62	34.66	30.25	29.13	33.26	49.06	55.80	43.23	36.62	37.15	43.09
2025	67.74	64.21	56.30	51.29	50.01	54.71	72.67	80.32	66.03	58.53	59.13	65.87
2026	69.13	65.52	57.46	52.34	51.04	55.83	74.16	81.96	67.39	59.72	60.35	67.22
2027	70.55	66.87	58.63	53.41	52.08	56.97	75.68	83.64	68.77	60.95	61.58	68.60
2028	71.85	68.10	59.72	54.40	53.05	58.03	77.06	85.17	70.03	62.07	62.72	69.86
2029	73.47	69.63	61.06	55.62	54.24	59.33	78.81	87.11	71.61	63.47	64.13	71.44
2030	74.97	71.06	62.31	56.76	55.35	60.55	80.42	88.89	73.08	64.77	65.44	72.90
2031	76.51	72.52	63.59	57.92	56.48	61.79	82.07	90.71	74.58	66.10	66.79	74.40
2032	77.79	73.73	64.64	58.87	57.41	62.81	83.45	92.25	75.83	67.20	67.90	75.64
2033	79.68	75.52	66.22	60.32	58.82	64.34	85.47	94.47	77.66	68.83	69.55	77.48
2034	81.37	77.13	67.64	61.62	60.09	65.73	87.28	96.47	79.32	70.31	71.04	79.13
2035	82.98	78.64	68.96	62.82	61.25	67.01	89.00	98.38	80.88	71.68	72.43	80.68
2036	84.43	80.03	70.17	63.92	62.33	68.18	90.57	100.11	82.30	72.94	73.70	82.10
2037	86.41	81.90	71.82	65.42	63.79	69.78	92.69	102.45	84.23	74.65	75.43	84.02
2038	88.18	83.58	73.29	66.76	65.10	71.21	94.59	104.55	85.95	76.18	76.97	85.75
2039	89.99	85.29	74.79	68.12	66.43	72.67	96.53	106.69	87.71	77.74	78.55	87.50
2040	91.64	86.86	76.17	69.39	67.67	74.02	98.30	108.64	89.33	79.18	80.00	89.11
2041	93.71	88.82	77.89	70.94	69.18	75.68	100.52	111.11	91.34	80.96	81.80	91.12
2042	95.63	90.64	79.48	72.40	70.60	77.23	102.58	113.38	93.22	82.62	83.48	92.99
2043	97.59	92.50	81.11	73.88	72.04	78.81	104.68	115.70	95.12	84.31	85.19	94.90
2044	99.30	94.12	82.53	75.17	73.31	80.19	106.52	117.74	96.80	85.79	86.68	96.56
2045	101.71	96.41	84.55	77.02	75.11	82.15	109.10	120.57	99.14	87.88	88.79	98.90

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)

Renewable Fixed Price Option (Continued)

TABLE 5b Renewable Avoided Costs Renewable Fixed Price Option for Wind QF Off-Peak Forecast ($/MWH)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2020	18.56	18.56	14.99	11.17	6.33	8.62	22.13	27.74	27.23	25.19	25.19	35.13
2021	32.83	30.33	23.94	14.04	10.56	12.13	26.26	31.48	29.29	27.59	28.47	34.79
2022	36.54	29.68	25.21	19.68	17.50	18.25	26.82	31.11	29.77	27.67	28.18	31.60
2023	33.58	29.96	25.44	19.86	17.66	18.41	27.07	31.41	30.05	27.93	28.45	31.90
2024	36.76	32.78	27.82	21.68	19.26	20.10	29.60	34.37	32.88	30.55	31.12	34.92
2025	41.82	37.29	31.65	24.68	21.93	22.88	33.68	39.10	37.40	34.76	35.40	39.72
2026	42.67	38.05	32.30	25.19	22.38	23.35	34.37	39.90	38.17	35.47	36.13	40.53
2027	43.55	38.83	32.96	25.70	22.84	23.82	35.07	40.72	38.95	36.20	36.87	41.36
2028	44.32	39.52	33.55	26.16	23.24	24.24	35.69	41.44	39.64	36.84	37.52	42.10
2029	45.35	40.44	34.33	26.77	23.78	24.81	36.53	42.40	40.56	37.70	38.39	43.08
2030	46.28	41.27	35.03	27.31	24.27	25.32	37.27	43.27	41.40	38.47	39.18	43.96
2031	47.23	42.11	35.75	27.87	24.77	25.84	38.04	44.16	42.24	39.26	39.98	44.86
2032	48.06	42.86	36.38	28.37	25.21	26.29	38.71	44.94	42.99	39.95	40.69	45.65
2033	49.18	43.86	37.23	29.03	25.79	26.91	39.61	45.99	43.99	40.88	41.64	46.72
2034	50.19	44.75	37.99	29.62	26.32	27.46	40.42	46.93	44.89	41.72	42.49	47.67
2035	51.22	45.67	38.77	30.23	26.86	28.02	41.25	47.89	45.81	42.57	43.36	48.65
2036	52.12	46.48	39.45	30.76	27.34	28.51	41.98	48.74	46.62	43.33	44.13	49.51
2037	53.34	47.56	40.37	31.48	27.97	29.18	42.96	49.87	47.71	44.34	45.16	50.66
2038	54.43	48.54	41.20	32.12	28.55	29.78	43.84	50.89	48.69	45.25	46.08	51.70
2039	55.55	49.53	42.04	32.78	29.13	30.39	44.74	51.94	49.68	46.17	47.03	52.76
2040	56.53	50.41	42.79	33.36	29.65	30.92	45.53	52.85	50.56	46.99	47.86	53.69
2041	57.84	51.58	43.79	34.14	30.34	31.65	46.59	54.09	51.74	48.08	48.97	54.94
2042	59.03	52.64	44.68	34.84	30.96	32.29	47.54	55.19	52.80	49.07	49.98	56.07
2043	60.24	53.72	45.60	35.55	31.59	32.95	48.52	56.33	53.88	50.07	51.00	57.22
2044	61.30	54.66	46.40	36.18	32.15	33.54	49.37	57.32	54.83	50.96	51.90	58.23
2045	62.73	55.94	47.48	37.02	32.90	34.32	50.53	58.66	56.11	52.15	53.11	59.59

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 6a Renewable Avoided Costs Renewable Fixed Price Option for Solar QF On-Peak Forecast ($/MWH)												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2020	22.37	22.12	17.53	15.24	13.20	18.04	41.23	51.93	35.11	27.72	28.74	41.23
2021	39.94	36.91	27.51	18.18	16.40	21.01	52.48	63.04	43.83	32.54	33.46	43.10
2022	43.21	37.35	29.21	24.27	21.79	26.57	46.98	55.76	40.35	32.82	33.79	43.37
2023	42.02	37.32	29.18	24.24	21.76	29.99	44.73	51.00	39.28	33.12	33.62	39.15
2024	43.61	40.50	33.55	29.13	28.01	32.14	47.95	54.68	42.11	35.50	36.04	41.97
2025	59.83	56.30	48.39	43.37	42.10	46.79	64.75	72.41	58.12	50.61	51.22	57.96
2026	61.06	57.45	49.38	44.26	42.96	47.75	66.08	73.89	59.31	51.65	52.27	59.15
2027	62.31	58.63	50.39	45.17	43.84	48.73	67.43	75.40	60.53	52.71	53.34	60.36
2028	63.44	59.69	51.31	45.99	44.64	49.62	68.65	76.76	61.62	53.66	54.31	61.45
2029	64.89	61.05	52.48	47.04	45.65	50.75	70.23	78.52	63.03	54.89	55.55	62.86
2030	66.22	62.30	53.56	48.00	46.59	51.79	71.66	80.13	64.32	56.01	56.69	64.15
2031	67.57	63.58	54.65	48.98	47.54	52.85	73.13	81.77	65.64	57.16	57.85	65.46
2032	68.72	64.66	55.57	49.80	48.34	53.74	74.38	83.17	66.76	58.13	58.83	66.57
2033	70.37	66.21	56.91	51.01	49.51	55.04	76.16	85.16	68.36	59.53	60.24	68.17
2034	71.85	67.61	58.12	52.10	50.57	56.20	77.76	86.94	69.80	60.79	61.52	69.61
2035	73.28	68.95	59.27	53.12	51.56	57.32	79.31	88.68	71.19	61.99	62.74	70.99
2036	74.57	70.16	60.31	54.05	52.46	58.32	80.71	90.24	72.44	63.08	63.84	72.24
2037	76.32	71.81	61.72	55.32	53.70	59.69	82.60	92.35	74.13	64.56	65.33	73.93
2038	77.88	73.28	62.99	56.46	54.80	60.91	84.29	94.25	75.65	65.88	66.67	75.45
2039	79.48	74.78	64.28	57.61	55.92	62.16	86.01	96.18	77.20	67.23	68.04	76.99
2040	80.91	76.13	65.45	58.66	56.94	63.29	87.57	97.91	78.60	68.45	69.27	78.39
2041	82.76	77.87	66.94	60.00	58.23	64.73	89.57	100.16	80.40	70.01	70.85	80.18
2042	84.46	79.47	68.31	61.23	59.43	66.06	91.41	102.21	82.04	71.45	72.31	81.82
2043	86.19	81.10	69.71	62.48	60.64	67.41	93.28	104.30	83.73	72.91	73.79	83.50
2044	87.70	82.52	70.93	63.57	61.70	68.59	94.92	106.14	85.19	74.19	75.08	84.96
2045	89.81	84.50	72.64	65.11	63.20	70.25	97.19	108.67	87.24	75.98	76.89	87.00

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD PPA (Continued)
Renewable Fixed Price Option (Continued)

TABLE 6b
Renewable Avoided Costs
Renewable Fixed Price Option for Solar QF
Off-Peak Forecast ($/MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2020	17.53	17.53	13.96	10.14	5.30	7.59	21.10	26.71	26.20	24.16	24.16	34.10
2021	31.78	29.28	22.89	12.99	9.51	11.07	25.21	30.43	28.24	26.54	27.42	33.74
2022	35.46	28.60	24.14	18.61	16.43	17.18	25.74	30.04	28.69	26.60	27.11	30.53
2023	32.49	28.86	24.35	18.76	16.56	17.32	25.97	30.31	28.95	26.84	27.35	30.81
2024	35.65	31.66	26.70	20.57	18.15	18.98	28.49	33.26	31.76	29.44	30.00	33.80
2025	40.68	36.15	30.51	23.54	20.79	21.74	32.54	37.96	36.26	33.62	34.26	38.58
2026	41.51	36.89	31.14	24.02	21.22	22.18	33.21	38.74	37.01	34.31	34.96	39.37
2027	42.36	37.64	31.78	24.51	21.65	22.64	33.89	39.53	37.76	35.01	35.68	40.18
2028	43.11	38.31	32.33	24.94	22.03	23.03	34.48	40.23	38.43	35.63	36.31	40.88
2029	44.11	39.20	33.09	25.53	22.55	23.57	35.29	41.17	39.33	36.46	37.16	41.84
2030	45.02	40.01	33.77	26.05	23.01	24.06	36.01	42.01	40.13	37.21	37.92	42.70
2031	45.94	40.82	34.46	26.59	23.48	24.55	36.75	42.87	40.96	37.97	38.70	43.57
2032	46.75	41.54	35.07	27.05	23.89	24.98	37.40	43.63	41.68	38.64	39.38	44.34
2033	47.84	42.51	35.89	27.69	24.45	25.57	38.27	44.65	42.65	39.54	40.30	45.38
2034	48.82	43.39	36.62	28.25	24.95	26.09	39.05	45.56	43.52	40.35	41.12	46.30
2035	49.82	44.27	37.37	28.83	25.47	26.62	39.85	46.49	44.42	41.18	41.97	47.25
2036	50.70	45.05	38.03	29.34	25.91	27.09	40.56	47.31	45.20	41.90	42.70	48.08
2037	51.88	46.11	38.92	30.03	26.52	27.73	41.50	48.42	46.26	42.88	43.70	49.21
2038	52.95	47.05	39.72	30.64	27.06	28.29	42.35	49.41	47.20	43.76	44.60	50.22
2039	54.03	48.02	40.53	31.27	27.62	28.87	43.22	50.42	48.17	44.66	45.51	51.25
2040	54.98	48.86	41.24	31.82	28.10	29.38	43.98	51.31	49.02	45.44	46.31	52.15
2041	56.27	50.00	42.21	32.56	28.76	30.07	45.01	52.51	50.16	46.51	47.40	53.37
2042	57.42	51.03	43.07	33.23	29.35	30.68	45.93	53.59	51.19	47.46	48.37	54.46
2043	58.60	52.07	43.96	33.91	29.95	31.31	46.87	54.68	52.24	48.43	49.36	55.58
2044	59.63	52.99	44.73	34.50	30.47	31.86	47.70	55.65	53.16	49.28	50.22	56.55
2045	61.02	54.23	45.77	35.31	31.19	32.61	48.82	56.95	54.40	50.44	51.40	57.88

Effective for service
on and after July 29, 2020

SCHEDULE 201 (Continued)

WIND INTEGRATION

TABLE 7		
Integration Costs		
Year	Wind	Solar
2020	0.33	1.36
2021	0.33	1.38
2022	0.34	1.41
2023	0.35	1.44
2024	0.35	1.47
2025	0.36	1.50
2026	0.37	1.53
2027	0.37	1.56
2028	0.38	1.59
2029	0.39	1.63
2030	0.40	1.66
2031	0.41	1.69
2032	0.41	1.73
2033	0.42	1.76
2034	0.43	1.80
2035	0.44	1.84
2036	0.45	1.87
2037	0.46	1.91
2038	0.47	1.95
2039	0.48	1.99
2040	0.49	2.03
2041	0.50	2.07
2042	0.51	2.12
2043	0.52	2.16
2044	0.53	2.21
2045	0.54	2.25

3. As-Available Rate

The As-Available Rate is based on the Avoided Energy Cost for surplus energy at the time of delivery. The As-Available Rate is equal to ~~eighty-five percent (85%) of the lower of 1)~~ the Avoided Energy Cost~~, or 2) the applicable Off-Peak Standard Avoided Cost or Off-Peak Renewable Avoided Cost pursuant to the Schedule in effect on the Effective Date (as defined in the Standard PPA) of the applicable PPA~~. The Company will purchase As-Available Energy at the As-Available Rate.

SCHEDULE 201 (Continued)

MONTHLY SERVICE CHARGE

Each separately metered QF not associated with a retail Customer account will be charged $10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard PPA:

1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than $1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment, that economic conditions or claims experience may warrant.

2) Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.

3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on their own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

SCHEDULE 201 (Continued)

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established pursuant to Commission rule, in the Company's Rules and Regulations (Rule C) or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE THE STANDARD FIXED PRICE OPTION OR THE RENEWABLE FIXED PRICE OPTION UNDER THE STANDARD PPA

A QF will be eligible to receive the Standard Fixed Price Option or the Renewable Fixed Price Option (as appropriate) under the Standard PPA if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the Same Person(s) or Affiliated Person(s), and located at the Same Site, does not exceed 3 MW for solar QF projects or 10 MW for all other types of QF projects. Solar QF projects with nameplate capacity (as calculated in this paragraph) that exceed 3 MW but do not exceed 10 MW are eligible for a Standard PPA containing negotiated prices under Schedule 202. A Community-Based or Family-Owned QF is exempt from these restrictions.

Definition of Community-Based

a. A community project (or a community sponsored project) must have a recognized and established organization located within the county of the project or within 50 miles of the project that has a genuine role in helping the project be developed and must have some not insignificant continuing role with or interest in the project after it is completed and placed in service.

b. After excluding the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, the equity (ownership) interests in a community sponsored project must be owned in substantial percentage (80 percent or more) by the following persons (individuals and entities): (i) the sponsoring organization, or its controlled affiliates; (ii) members of the sponsoring organization (if it is a membership organization) or owners of the sponsorship organization (if it is privately owned); (iii) persons who live in the county in which the project is located or who live a county adjoining the county in which the project is located; or (iv) units of local government, charities, or other established nonprofit organizations active either in the county in which the project is located or active in a county adjoining the county in which the project is located.

Definition of Family-Owned

After excluding the ownership interest of the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, five or fewer individuals own 50 percent or more of the equity of the project entity, or fifteen or fewer individuals own 90 percent or more of the project entity. A "look through" rule applies to closely held entities that hold the project entity, so that equity held by LLCs, trusts, estates, corporations, partnerships or other similar entities is considered

SCHEDULE 201 (Continued)

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE THE STANDARD FIXED PRICE OPTION OR THE RENEWABLE FIXED PRICE OPTION UNDER THE STANDARD PPA (Continued)

held by the equity owners of the look through entity. An individual is a natural person. In counting to five or fifteen, spouses or children of an equity owner of the project owner who also have an equity interest are aggregated and counted as a single individual.

Definition of Person(s) or Affiliated Person(s)

As used above, the term “Same Person(s)” or “Affiliated Person(s)” means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) solely because they are developed by a single entity.

Furthermore, two facilities will not be held to be owned or controlled by the Same Person(s) or Affiliated Person(s) if such common person or persons is a “passive investor” whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a “passive investor” in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Definition of Same Site

For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for standard pricing or negotiated pricing under the Standard PPA is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for standard pricing or negotiated pricing under the Standard PPA is sought.

Definition of Shared Interconnection and Infrastructure

QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to standard pricing or negotiated pricing under the Standard PPA will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for standard pricing or negotiated pricing under the Standard PPA so long as the use of the shared interconnection complies with the interconnecting utility’s safety and reliability standards, interconnection agreement requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility’s approved Standard PPA.

SCHEDULE 201 (Continued)

OTHER DEFINITIONS

As-Available Energy

As-Available Energy means 1) all Net Output delivered to PGE if Seller elected the As-Available Rate option within a Standard PPA, or 2) (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any Contract Year as defined under the Standard PPA year; ; and (c) for deliveries above the nameplate capacity in any hour.
Deliveries pursuant to an Off-System PPA that are above the nameplate capacity in any hour solely for the purpose of accommodating hourly scheduling in whole megawatts by a third-party transmission provider will not be subject to the As-Available Rate.

Mid-C Index Price

As used in this schedule, the daily Mid-C Index Price shall be the applicable day-ahead Intercontinental Exchange ("ICE") Mid-C Physical Peak (bilateral) or Mid-C Physical Off-Peak (bilateral) indices representative of the OTC market for WSPP Schedule-C physical Firm Energy transactions at the Mid-C trading hub. Product details for the Mid-C Physical Peak (bilateral) or Mid-C Physical Off-Peak (bilateral) are found on the following website: https://www.theice.com/products/OTC/Physical-Energy/Electricity. In the event ICE no longer publishes this index, PGE and the Seller agree to select an alternative successor index representative of the Mid-C trading hub.

Avoided Energy Cost:

The Avoided Energy Cost means eighty-two and four tenths percent (82.4%) of the monthly arithmetic average of each day's ICE Mid-C Physical Peak (bilateral) and Mid-C Physical Off-Peak (bilateral) average index prices. Each day's index prices will reflect the relative proportions of peak hours and off-peak hours in the month as follows:

$$.824 * \left(\sum_{X=1}^{n} \{(\text{ICE Mid-C Physical Peak (bilateral) Avg}_X * \text{applicable peak index hours for day}) + (\text{ICE Mid-C Physical Off-Peak (bilateral) Avg}_X * \text{applicable off-peak index hours for day})\} / (n*24)\right)$$

where n = number of days in the month

Definition of RPS Attributes

As used in this schedule, RPS Attributes means all attributes related to the Net Output generated by the Facility that are required in order to provide PGE with "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. 469A.010, in effect at the time of execution of this Agreement. RPS Attributes do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.

Definition of Environmental Attributes

As used in this schedule, Environmental Attributes shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (C02), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

Definition of Resource Sufficiency Period

This is the period from the current year through 2024.

Definition of Resource Deficiency Period

This is the period from 2025.

Definition of Renewable Resource Sufficiency Period

This is the period from the current year through 2024.

Definition of Renewable Resource Deficiency Period

This is the period from 2025.

SCHEDULE 201 (Concluded)

DISPUTE RESOLUTION

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to standard pricing or negotiated pricing under the Standard PPA.

The QF may present disputes to the Commission for resolution using the following process:

The QF may file a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract. The QF may not file such a complaint during any 15-day period in which the utility has the obligation to respond, but must wait until the 15-day period has passed.

The utility may respond to the complaint within ten days of service.

The Commission will limit its review to the issues identified in the complaint and response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. See OAR 860, Division 016. The administrative law judge will not act as an arbitrator.

SPECIAL CONDITIONS

1. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.

2. If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller's retail Electricity Service bill. At the option of the Customer, any net credit over $10.00 will be paid by check to the Customer.

3. Unless required by state or federal law, if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed, PPAs entered into pursuant to this schedule will not terminate prior to the Standard or Negotiated PPA's termination date.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years from the commercial operation date selected by the Seller and memorialized in the PPA.

UM 2060

Attachment -B

Redline and Clean copy of

PGE's Sch 202 As Available

Rate

SCHEDULE 202
QUALIFYING FACILITIES GREATER THAN 10MW
AVOIDED COST POWER PURCHASE INFORMATION

PURPOSE

To provide information regarding procedures and timelines leading to a power purchase agreement between the Company and a Qualifying Facility (QF) with an aggregate nameplate capacity greater than 10,000 kW.

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

To qualifying cogeneration facilities or qualifying small power production facilities within the meaning of section 201 and 210 of the Public Utility Regulatory Act of 1978 (PURPA), 16 U.S.C. 796 and 824a-3.

A QF with nameplate capacity greater than 10,000 kW will be required to enter into a negotiated written power purchase agreement (Negotiated Agreement) with the Company.

A QF with nameplate capacity less than 10,000 kW or less may elect the option of a Standard Contract with terms and pricing as defined in Schedule 201.

POWER PURCHASE INFORMATION

A QF may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

GUIDELINES

The Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, that is made available to Company by the Seller, pursuant to a Negotiated Agreement with the Company executed prior to delivery of such power. The Negotiated Agreement will comply with the requirements of the Federal Energy Regulatory Commission (FERC) and the guidelines established by Commission Order No. 07-360.

The Negotiated Agreement may have a term of up to 20 years, as selected by the Seller.

SCHEDULE 202 (Continued)

PROCEDURES TO DEVELOP A NEGOTIATED AGREEMENT

1. The Seller may request indicative power purchase prices. To obtain an indicative pricing proposal for a proposed project, the Seller must provide in writing, general project information reasonably required for the development of indicative pricing, including, but not limited to:

   - Demonstration of ability to obtain QF status.
   - Design capacity (MW), station service requirements, and net amount of power to be delivered to the Company's electric system.
   - Generation technology and other related technology applicable to the site.
   - Quantity and timing of monthly power deliveries (including project ability to respond to dispatch orders from the Company).
   - Proposed site location and electrical interconnection point.
   - Status of interconnection and transmission arrangements.
   - Proposed on-line date and outstanding permitting requirements.
   - Motive force or fuel plan consisting of fuel type(s) and source(s).
   - Proposed contract term and pricing provisions.

2. The Company will not be obligated to provide an indicative pricing proposal until all the information described above has been received in writing from the Seller. Within 30 business days following receipt of all required information, the Company will provide the Seller with an indicative pricing proposal, which may include other terms and conditions, tailored to the individual characteristics of the proposed project. Such proposal may be used by the Seller to make determinations regarding project planning, financing and feasibility. However, such prices are indicative and are not final and binding. Prices and other terms and conditions are only final and binding to the extent contained in Negotiated Agreement, once executed by both parties. The Company will provide with the indicative prices a description of the methodology used to develop the prices.

SCHEDULE 202 (Continued)

PROCEDURES TO DEVELOP A NEGOTIATED AGREEMENT (Continued)

3. The Avoided Cost Prices specified in Schedule 201 provide a starting point for indicative prices, and will be modified to address the following specific factors established in OPUC Order No. 07-360 and FERC 18 § CFR 292.304(e):

(e) Factors affecting rates for purchases. In determining avoided costs, the following factors will, to the extent practicable, be taken into account.

(1) The data provided pursuant to 18 CFR § 292.302(b), (c), or (d), including State review of any such data;

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the Company to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the Company's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the Company's system; and

(vii) The smaller capacity increments and the shorter lead time available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in part (e) (2) of this section, to the ability of the Company to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the Company generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

SCHEDULE 202 (Continued)

PROCEDURES TO DEVELOP A NEGOTIATED AGREEMENT (Continued)

4. If the Seller desires to proceed with negotiations after reviewing the Company's indicative price proposal, the Seller must request in writing that the Company prepare a draft Negotiated Agreement to serve as the basis for negotiations between the parties. In connection with such request, the Seller must provide the Company with any additional project information that the Company reasonably determines to be necessary for the preparation of the Negotiated Agreement, which may include, but will not be limited to:

   - Updated information for the project information listed above in paragraphs 1 and 3.
   - Evidence of adequate control of proposed site.
   - Timelines for obtaining any necessary governmental permits, approvals or authorizations.
   - Assurance of fuel supply or motive force.
   - Anticipated timelines for completion of key project milestones.
   - Evidence that any necessary interconnection studies have been completed and assurance that the necessary interconnection arrangements have been executed or are under negotiation.

5. Within 30 days following receipt of updated information required by the Company, the Company will provide the Seller with a draft Negotiated Agreement. The draft agreement will contain proposed terms and conditions in addition to indicative pricing. The draft agreement is not binding; however; it will serve as the basis for subsequent negotiations.

6. After reviewing the draft Negotiated Agreement, the Seller will notify the Company in writing of its intent to proceed with negotiations. The Seller may prepare an initial set of written comments and proposals regarding the agreement and forward them to the Company. The Company will not be obligated to begin negotiations with a Seller until the Company has received an initial set of written comments. After the Company's receipt of comments and proposals, the Seller may contact the Company to schedule contract negotiations at such times and places as are mutually agreeable to the parties. In connection with such negotiations, the Company:

   - Will not unreasonably delay negotiations and will respond in good faith to any additions, deletions or modifications to the draft Negotiated Agreement that are proposed by the Seller.
   - May request to visit the site of the proposed project if such a visit has not previously occurred.
   - Will update its pricing proposals at appropriate intervals to accommodate any changes to the Company's avoided-cost calculations, the proposed project or proposed terms of the draft Negotiated Agreement.
   - May request any additional information from the Seller necessary to finalize the terms of the Negotiated Agreement and satisfy the Company's due diligence regarding the QF project.

SCHEDULE 202 (Concluded)

PROCEDURES TO DEVELOP A NEGOTIATED AGREEMENT (Continued)

7. When both parties are in full agreement as to all terms and conditions of the draft Negotiated Agreement, the Company will prepare and forward to the Seller a final, executable version of the agreement within 15 business days. Prices and other terms and conditions in the Negotiated Agreement will not be final and binding until the agreement has been executed by both parties.

8. If parties are not in full agreement within 60 days from the date of written notice, the Seller may file a complaint with the Commission asking the Commission to adjudicate the disputed contract terms.

OFF SYSTEM POWER PURCHASE AGREEMENT

A QF that interconnects with an electric system other than the Company's electric system may enter into a power purchase agreement with the Company after following the applicable negotiated contract guidelines and making the arrangements necessary for transmission of power to the Company's system.

AS-AVAILABLE RATE

The As-Available Rate is the price, as defined in Schedule 201, applicable to QFs requesting non-firm PPAs greater than 10 MW.

Effective for service
on and after ~~April 8~~July 29, 2020

SCHEDULE 202
QUALIFYING FACILITIES GREATER THAN 10MW
AVOIDED COST POWER PURCHASE INFORMATION

PURPOSE

To provide information regarding procedures and timelines leading to a power purchase agreement between the Company and a Qualifying Facility (QF) with an aggregate nameplate capacity greater than 10,000 kW.

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

To qualifying cogeneration facilities or qualifying small power production facilities within the meaning of section 201 and 210 of the Public Utility Regulatory Act of 1978 (PURPA), 16 U.S.C. 796 and 824a-3.

A QF with nameplate capacity greater than 10,000 kW will be required to enter into a negotiated written power purchase agreement (Negotiated Agreement) with the Company.

A QF with nameplate capacity less than 10,000 kW or less may elect the option of a Standard Contract with terms and pricing as defined in Schedule 201.

POWER PURCHASE INFORMATION

A QF may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

GUIDELINES

The Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, that is made available to Company by the Seller, pursuant to a Negotiated Agreement with the Company executed prior to delivery of such power. The Negotiated Agreement will comply with the requirements of the Federal Energy Regulatory Commission (FERC) and the guidelines established by Commission Order No. 07-360.

The Negotiated Agreement may have a term of up to 20 years, as selected by the Seller.

SCHEDULE 202 (Continued)

PROCEDURES TO DEVELOP A NEGOTIATED AGREEMENT

1. The Seller may request indicative power purchase prices. To obtain an indicative pricing proposal for a proposed project, the Seller must provide in writing, general project information reasonably required for the development of indicative pricing, including, but not limited to:

   - Demonstration of ability to obtain QF status.
   - Design capacity (MW), station service requirements, and net amount of power to be delivered to the Company's electric system.
   - Generation technology and other related technology applicable to the site.
   - Quantity and timing of monthly power deliveries (including project ability to respond to dispatch orders from the Company).
   - Proposed site location and electrical interconnection point.
   - Status of interconnection and transmission arrangements.
   - Proposed on-line date and outstanding permitting requirements.
   - Motive force or fuel plan consisting of fuel type(s) and source(s).
   - Proposed contract term and pricing provisions.

2. The Company will not be obligated to provide an indicative pricing proposal until all the information described above has been received in writing from the Seller. Within 30 business days following receipt of all required information, the Company will provide the Seller with an indicative pricing proposal, which may include other terms and conditions, tailored to the individual characteristics of the proposed project. Such proposal may be used by the Seller to make determinations regarding project planning, financing and feasibility. However, such prices are indicative and are not final and binding. Prices and other terms and conditions are only final and binding to the extent contained in Negotiated Agreement, once executed by both parties. The Company will provide with the indicative prices a description of the methodology used to develop the prices.

SCHEDULE 202 (Continued)

PROCEDURES TO DEVELOP A NEGOTIATED AGREEMENT (Continued)

3. The Avoided Cost Prices specified in Schedule 201 provide a starting point for indicative prices, and will be modified to address the following specific factors established in OPUC Order No. 07-360 and FERC 18 § CFR 292.304(e):

(e) Factors affecting rates for purchases. In determining avoided costs, the following factors will, to the extent practicable, be taken into account.

(1) The data provided pursuant to 18 CFR § 292.302(b), (c), or (d), including State review of any such data;

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the Company to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the Company's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the Company's system; and

(vii) The smaller capacity increments and the shorter lead time available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in part (e) (2) of this section, to the ability of the Company to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the Company generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

SCHEDULE 202 (Continued)

PROCEDURES TO DEVELOP A NEGOTIATED AGREEMENT (Continued)

4. If the Seller desires to proceed with negotiations after reviewing the Company's indicative price proposal, the Seller must request in writing that the Company prepare a draft Negotiated Agreement to serve as the basis for negotiations between the parties. In connection with such request, the Seller must provide the Company with any additional project information that the Company reasonably determines to be necessary for the preparation of the Negotiated Agreement, which may include, but will not be limited to:

   - Updated information for the project information listed above in paragraphs 1 and 3.
   - Evidence of adequate control of proposed site.
   - Timelines for obtaining any necessary governmental permits, approvals or authorizations.
   - Assurance of fuel supply or motive force.
   - Anticipated timelines for completion of key project milestones.
   - Evidence that any necessary interconnection studies have been completed and assurance that the necessary interconnection arrangements have been executed or are under negotiation.

5. Within 30 days following receipt of updated information required by the Company, the Company will provide the Seller with a draft Negotiated Agreement. The draft agreement will contain proposed terms and conditions in addition to indicative pricing. The draft agreement is not binding; however; it will serve as the basis for subsequent negotiations.

6. After reviewing the draft Negotiated Agreement, the Seller will notify the Company in writing of its intent to proceed with negotiations. The Seller may prepare an initial set of written comments and proposals regarding the agreement and forward them to the Company. The Company will not be obligated to begin negotiations with a Seller until the Company has received an initial set of written comments. After the Company's receipt of comments and proposals, the Seller may contact the Company to schedule contract negotiations at such times and places as are mutually agreeable to the parties. In connection with such negotiations, the Company:

   - Will not unreasonably delay negotiations and will respond in good faith to any additions, deletions or modifications to the draft Negotiated Agreement that are proposed by the Seller.
   - May request to visit the site of the proposed project if such a visit has not previously occurred.
   - Will update its pricing proposals at appropriate intervals to accommodate any changes to the Company's avoided-cost calculations, the proposed project or proposed terms of the draft Negotiated Agreement.
   - May request any additional information from the Seller necessary to finalize the terms of the Negotiated Agreement and satisfy the Company's due diligence regarding the QF project.

SCHEDULE 202 (Concluded)

PROCEDURES TO DEVELOP A NEGOTIATED AGREEMENT (Continued)

7. When both parties are in full agreement as to all terms and conditions of the draft Negotiated Agreement, the Company will prepare and forward to the Seller a final, executable version of the agreement within 15 business days. Prices and other terms and conditions in the Negotiated Agreement will not be final and binding until the agreement has been executed by both parties.

8. If parties are not in full agreement within 60 days from the date of written notice, the Seller may file a complaint with the Commission asking the Commission to adjudicate the disputed contract terms.

OFF SYSTEM POWER PURCHASE AGREEMENT

A QF that interconnects with an electric system other than the Company's electric system may enter into a power purchase agreement with the Company after following the applicable negotiated contract guidelines and making the arrangements necessary for transmission of power to the Company's system.

AS-AVAILABLE RATE

The As-Available Rate is the price, as defined in Schedule 201, applicable to QFs requesting non-firm PPAs greater than 10 MW.

Effective for service
on and after July 29, 2020