BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 18-07-003 (Filed July 12, 2018)

SUBMISSION BY PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) OF ITS FINAL, CONFORMING 2018 RENEWABLE ENERGY PROCUREMENT PLAN

(PUBLIC VERSION)

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Dated: March 15, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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Pursuant to Ordering Paragraph 2 of California Public Utilities Commission's ("Commission") Decision ("D.") 19-02-007, Pacific Gas and Electric Company ("PG&E") is submitting its Final, Conforming 2018 Renewable Energy Procurement Plan ("Final 2018 RPS Plan"). The Final 2018 RPS Plan is attached to this cover pleading in both a clean version and a redline version showing changes made to its Revised Draft 2018 RPS Plan filed on October 8, 2018.

The changes made in the Final 2018 RPS Plan conform it to the requirements and modifications authorized and set forth in D.19-02-007. In summary, these changes include:

1. Including a framework governing the sale of Renewable Energy Credits associated with certain biomass contracts, consistent with D.18-12-003 and the further direction set forth in D.19-02-007;[1]
2. Describing the potential impacts of Senate Bill 901, as implemented by Commission Resolution E-4977, on PG&E's Renewable Net Short position;[2]
3. Describing PG&E's election to use information-only Time of Delivery factors;[3]
4. Incorporating the changes sought by PG&E in its December 21, 2018 Motion to

[1] D.18-12-003, Ordering Paragraph ("OP") 3; D.19-02-007, pp. 108-109.
[2] D.19-02-007, OP 15.
[3] *Id.*, OP 16.

Update its Draft 2018 RPS Plan, which Motion was granted by the Commission;[4]

5. Adding clarifying language, consistent with the D.19-02-007, that requires PG&E to seek Commission authorization to voluntarily procure incremental RPS products during the 2018 RPS Plan cycle;[5]

6. Updating PG&E's description of its Least-Cost, Best-Fit methodology to include the Project Viability Calculator;[6] and

7. Conforming PG&E's RPS Sales Protocol with its approved RPS Sales Framework.[7]

Pursuant to D.19-02-007, PG&E will deem its Final 2018 RPS Plan to be accepted by the Commission unless this filing is suspended by the Energy Division by March 22, 2019, which is 7 days from the date of this submission.[8]

Respectfully Submitted,

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By: */s/ M. Grady Mathai-Jackson*
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Dated: March 15, 2019

[4] *Id.*, OP 21.

[5] *Id.*, OP 13.

[6] *Id.*, OP 12.

[7] *See id.*, OP 1 (adopting PG&E's Revised Draft 2018 RPS Plan, including the proposed RPS Sales Framework, except for those modifications otherwise ordered).

[8] *Id.*, OP 2.

VERIFICATION

I, Alexander Allan, am an employee of Pacific Gas and Electric Company, a corporation, and am authorized to make this verification on its behalf. I have read the foregoing:

SUBMISSION BY PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) OF ITS FINAL, CONFORMING 2018 RENEWABLE ENERGY PROCUREMENT PLAN

(PUBLIC VERSION)

The statements in the foregoing document are true to my own knowledge, except as to matters which are therein stated on information and belief, and as to those matters I believe them to be true. I declare under penalty of perjury that the foregoing is true and correct.

Executed on this 15th day of March, 2019 at San Francisco, California

/s/ Alexander Allan

ALEXANDER ALLAN
Principal, Portfolio and Resource Forecasting
Pacific Gas and Electric Company

PACIFIC GAS AND ELECTRIC COMPANY

RENEWABLES PORTFOLIO STANDARD

FINAL, CONFORMING 2018 RENEWABLE ENERGY PROCUREMENT PLAN

MARCH 15, 2019

PUBLIC VERSION

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LIST OF APPENDICES

Pacific Gas and Electric Company ("PG&E") respectfully submits its Revised Draft 2018 Renewables Portfolio Standard ("RPS") Plan ("2018 RPS Plan") to the California Public Utilities Commission ("CPUC" or "Commission") as directed by the Commission in the *Assigned Commissioner And Assigned Administrative Law Judge's Ruling Identifying Issues And Schedule Of Review For 2018 Renewables Portfolio Standard Procurement Plans* (the "2018 RPS Plan Ruling").[1] PG&E's 2018 RPS Plan begins with summaries of the key issues and important legislative and regulatory developments impacting California's RPS requirements, and then addresses each of the specific requirements identified in the 2018 RPS Plan Ruling.[2] PG&E has also included in its final 2018 RPS Plan a Framework for Tree Mortality Non-Bypassable Charge Renewable Energy Credit Sales Solicitation, as required by Commission Decision ("D.") 18-12-003.[3] This Framework is set forth in Appendix J.

1. Summary of Key Issues

1.1. Assuming No Power Charge Indifference Adjustment Reform, PG&E Has No Need for Additional RPS Resources Until After 2030

PG&E is currently well-positioned to meet its RPS compliance requirements and does not project to have incremental physical need[4] for RPS resources until at least 2026. PG&E projects that it will have incremental RPS procurement need after 2033, after applying volumes of RPS procurement above the requirement from past years

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1 2018 RPS Plan Ruling, file June 21, 2018 in Rulemaking ("R.") 15-02-020, p. 21 (Ordering Paragraph ("OP") 1.

2 *See* 2018 RPS Plan Ruling, pp. 2-22.

3 D.18-12-003, OP 3.

4 Situation in which actual deliveries from RPS resources in a given year or compliance period is less than the corresponding RPS interim target or compliance period requirement. In this situation the Bank may be used in part to meet any applicable RPS compliance target.

("Bank") toward its current-year RPS needs beginning in 2026.[5] However, PG&E's RPS need is subject to considerable uncertainty, including the following:

1. If the Joint investor-owned utilities' ("IOU") proposed Green Allocation Mechanism is adopted as part of the Power Charge Indifference Adjustment ("PCIA") Reform proceeding, PG&E's procurement and sales strategies would change dramatically and result in a near-term need for RPS procurement.
2. Expected increases in customers switching to service from Community Choice Aggregators ("CCA") and generating their own electricity have resulted in dramatic decreases in the IOUs' bundled retail sales projections. As retail sales decrease, the quantity of RPS energy required for PG&E to meet its RPS obligation falls, resulting in a decreased need for new RPS resources.
3. The analysis in this 2018 RPS Plan has been updated to incorporate the revised RPS requirements as set forth by Senate Bill ("SB") 100,[6] which was signed by the Governor on September 10, 2018. Otherwise, this 2018 RPS Plan assumes the current RPS law remains unchanged and that the Commission does not exercise its authority to raise the RPS requirements for retail sellers. However, legislation enacted after this date and actions taken in the Commission's RPS proceeding can change these inputs.

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5 In prior versions of its RPS Plan, PG&E has redacted its RPS need year, consistent with the May 21, 2014, Administrative Law Judge's ("ALJ") Ruling on Renewable Net Short ("RNS") issued in R.11-05-005, pages 5 and 24, which established confidentiality rules associated with portfolio optimization. PG&E is waiving this confidentiality in this limited instance in order to allow for public transparency concerning PG&E's proposals to manage its RPS portfolio and concerning PG&E's need for incremental mandated procurement. In doing so, PG&E reserves the right to redact its need year and similar portfolio optimization information in future versions of its RPS Plan. The ability to redact future need is particularly critical when PG&E expects a near-term net short position.

6 SB 100, Stats. 2018, Ch. 312 (De León).

1.2. PG&E Proposes Not to Hold a Solicitation to Procure in 2019

Given its current RPS compliance position, PG&E is proposing not to hold an RPS procurement solicitation for the 2018 solicitation cycle. PG&E will seek Commission approval to procure any incremental RPS products during this RPS Plan cycle, other than the mandated programs referenced below.

Although many factors, including those described above, could change its RPS compliance position, PG&E believes that its existing portfolio of executed RPS contracts, its owned RPS-eligible generation, and its expected Bank balances will be more than adequate to ensure compliance with near-term RPS requirements. Additionally, even without an RPS solicitation, PG&E expects to continue to procure additional volumes of incremental RPS-eligible contracts through mandated procurement programs during the 2018 solicitation cycle (which is expected to occur during the calendar year 2019).[7]

1.3. PG&E Plans to Continue to Sell RPS Volumes in 2019

As load has shifted to non-IOU suppliers and developers have overcome early obstacles in the RPS Program and projects have become increasingly viable, PG&E has shifted from a focus on incremental procurement to now managing and optimizing its existing RPS portfolio, including through sales of RPS volumes. PG&E proposes to pursue short-term RPS sales in 2019. Additionally, PG&E may pursue long-term RPS sales after Phase 2 of the Power Charge Indifference Adjustment Rulemaking ("PCIA OIR") is resolved, depending on the outcome in that proceeding. This will help to address the fact that PG&E's forecasted RPS position predicts a higher cumulative

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7 Mandated programs include Renewable Market Adjusting Tariff ("ReMAT"), the Bioenergy Market Adjusting Tariff ("BioMAT"), and any new or extended biomass contracts pursuant to SB 901. The ReMAT program is currently the subject of litigation in federal court, and the Commission has issued a new Order Instituting Rulemaking ("OIR") to consider further implementation of the Federal Public Utility Regulatory Policies Act of 1978 ("PURPA"), which will consider adoption of a new mandate to procure from RPS-eligible facilities that are Qualifying Facilities ("QF") under federal law. *See generally* R.18-07-017. In addition, while it will not directly impact PG&E's RNS, PG&E expects to procure additional volumes over the next year for the Green Tariff Shared Renewables ("GTSR") Program.

Bank than its calculated minimum Bank needed to ensure compliance in light of regular fluctuations in supply and demand.

In 2018, PG&E issued a second solicitation for sales of RPS products and participated in other retail sellers' RPS procurement solicitations. PG&E used its Commission-approved RPS sales framework (the "RPS Sales Framework") to assess sales opportunities. PG&E is updating the RPS Sales Framework as part of this 2018 RPS Plan and intends to use the revised RPS Sales Framework, if approved, in 2019 to target issuing three, with a minimum of two, sales solicitations.[8]

The goal of PG&E's RPS Sales Framework is to prudently manage PG&E's portfolio with a focus on customer affordability, while continuing to maintain compliance with the RPS Program. As described more fully in Section 4, below, updates proposed in this RPS planning cycle to the RPS Sales Framework may result in significantly higher volumes of sales from PG&E's RPS portfolio in 2019 than occurred in 2018. If the market conditions support sales at the highest levels allowed under the proposed revisions to the RPS Sales Framework, the volumes would far exceed the ~2,000 gigawatt-hour ("GWh") per year assumed, based on the results of PG&E's 2017 sales solicitation, for purposes of quantitative modeling in this 2018 RPS Plan. If sales at the higher volumes allowed by revisions to the RPS Sales Framework were realized in 2019, the higher volumes would be incorporated into PG&E's RNS calculations going forward and included in future RPS Plans.

The volume of sales at the high end allowed by the revised RPS Sales Framework would cause physical deliveries of RPS-eligible products to PG&E to fall well below the annual RPS interim targets and compliance period statutory requirements in some future years. However, PG&E projects that it will be able to comply with all existing RPS requirements in the near-term even under a scenario in which it executes the maximum volume of sales proposed by the revised RPS Sales

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8 Additional detail on PG&E's planned sales solicitations is described in Section 4.

Framework since it has adequate volumes in its historical long position[9] to make up any difference between physical deliveries and the near-term RPS requirements.

It is unclear whether market participants will offer prices for RPS-eligible products at levels that would result in selling the maximum volumes of RPS-eligible products allowed by the revised RPS Sales Framework. In the past, PG&E has not received sufficient market interest in order to sell all of the volumes it has offered in solicitations. Nonetheless, for the reasons described more fully in Section 4, it is in the interest of PG&E's customers to attempt to sell significantly higher volumes of RPS products in this RPS planning cycle to the extent the level of market demand sustains adequate prices.

1.4. PG&E Opposes Mandates That Result in Unnecessary and/or Unreasonable Costs for Its Customers

Despite PG&E's absence of need for additional RPS resources, PG&E continued in 2018 to procure required RPS-eligible volumes through mandated procurement programs such as the BioMAT program and the solar photovoltaic Renewable Auction Mechanism ("PV RAM") program. In 2017, for example, PG&E held 18 auctions/solicitations[10] to fulfill mandated program requirements, despite being granted approval by the Commission to not hold an RPS solicitation due to lack of RPS need.

Wherever consistent with law, PG&E will continue to oppose new RPS procurement mandates, to seek to suspend existing RPS procurement mandates, and to oppose any changes to existing RPS procurement mandates that would require additional procurement. In general, PG&E believes that no RPS procurement should be mandated without a clear demonstration of need.

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9 Throughout this 2018 RPS Plan, PG&E uses the phrase "historical long position" to refer to volumes in its existing Bank plus historical RPS volumes that have generated above the annual RPS compliance targets in a current compliance period.

10 PG&E has held bi-monthly auctions for ReMAT since November 1, 2013 (until the program was suspended at the end of 2017, as further described below) and for BioMAT since February 1, 2016. PG&E also held one PV RAM solicitation in 2018.

Even if PG&E had near-term RPS need, PG&E would still not support expansion of existing mandated programs or additional new mandated programs. Mandated procurement programs do not optimize costs for customers because they restrict flexibility and optionality to achieve the RPS targets by mandating procurement through a potentially less efficient and more costly manner. PG&E supports a technology-neutral procurement process, in which all RPS-eligible technologies can compete to demonstrate which projects provide the best value to customers at the lowest cost.

Finally, PG&E continues to be concerned about the cost burden that procurement mandates place on bundled customers and will seek to ensure all customers, both bundled and departed load, equitably bear the costs of additional and existing mandates. Mandated procurement through Bioenergy Renewable Auction Mechanism ("BioRAM"), BioMAT, ReMAT, and the PV RAM benefits all customers and thus all customers should pay their equitable share of those costs.

1.5. PG&E's RPS Procurement and Sales Strategies Are Highly Dependent on the Resolution of the PCIA Reform Proceeding

The Commission is considering whether and how to revise the existing PCIA in R. 17-06-026. While the Commission issued a Proposed Decision ("PD") in that proceeding on August 1, 2018, a final decision will not be adopted prior to the filing of the draft version of this 2018 RPS Plan. Until the Commission issues a final decision in its PCIA reform docket, the RPS portfolio position and RPS procurement and sales strategies described in this draft plan are highly uncertain and contingent.[11]

This Plan may need updates, or even need to be re-filed, if the PCIA Reform proceeding concludes in a decision that allocates significant portions of PG&E's RPS portfolio to other retail sellers, as the joint IOUs have proposed in R.17-06-026. That decision would materially impact PG&E's RNS position, as described more fully in the following sub-section.

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11 PG&E notes that the PD issued ins R.17-06-026 would not eliminate these uncertainties and contingencies even if adopted as proposed. The PD would initiate a new phase of R.17-06-026 in which the Commission will continue to consider portfolio management and may direct PG&E to take actions that impact its current RPS position.

Unless otherwise explicitly noted, the analysis provided in this draft version of the 2018 RPS Plan assumes no reform of the existing PCIA, and therefore no allocation of PG&E's RPS portfolio to other retail sellers. If the final decision issued in R.17-06-026 revises the PCIA methodology in a way that impacts PG&E's RNS, PG&E will either incorporate those changes into an update of the 2018 RPS Plan according to the schedule set forth in the 2018 RPS Plan Ruling, as amended,[12] or it will seek permission to revise or re-file its 2018 RPS Plan on another timeline.

2. Summary of Important Recent Legislative/Regulatory Changes to the RPS Program

PG&E's portfolio forecast and procurement decisions are influenced by legislative and regulatory changes related to the RPS Program. While bills recently signed by the Governor will likely change PG&E's RPS position and need, the quantitative analysis provided in this 2018 RPS Plan only considers statutes enacted as of September 19, 2018. Legislation enacted after September 19, 2018, that will likely impact PG&E's RNS in the future, depending on how these bills are implemented, includes SB 237,[13] which is expected to increase the participation cap for the State's Direct Access program by 4,000 GWh statewide, and SB 901,[14] which requires the IOUs to seek to extend the delivery terms of RPS-eligible biomass contracts that meet certain feedstock and other requirements. Resolution E-4977, which amends the BioRAM Program pursuant to SB 901, requires PG&E to seek additional procurement from certain BioRAM and other biomass contracts. However, the volume of the additional procurement and the terms of the procurement are unknown at this time and are thus not reflected in the RNS calculations. Any executed contract extensions

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12 See Administrative Law Judge Mason's E Mail Ruling Granting, in part, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company Request for Extension to the 2018 RPS Plan Schedule, sent to the Service List for R.15-02-020 on July 9, 2018 (extending deadline for filing Motions to Update the Draft RPS Plans to September 28, 2018).

13 SB 237, Stats. 2018, Ch. 600 (Hertzberg). SB 237 requires the Commission to issue an order implementing SB 237 by June 1, 2019.

14 SB 901, Stats. 2018, Ch. 626 (Dodd).

pursuant to SB 901 will be reflected in future RNS and RPS Plan updates. As a general matter, PG&E expects that implementation of SB 237 and SB 901 will increase PG&E's long position with regard to the RPS targets and so will not change the fundamental proposals in this 2018 RPS Plan to pursue RPS sales and to not undertake a procurement solicitation in 2019.

The following section summarizes recent legislative and regulatory developments that may impact PG&E's RPS Program. Specifically, this section addresses: (1) the adoption of SB 100; (2) the adoption and implementation of SB 350; (3) mandated procurement programs, including RAM, ReMAT, bioenergy procurement program ("BioRAM"), and BioMAT; (4) the pending Integrated Resource Plan ("IRP") proceeding at the CPUC; (5) the approved Diablo Canyon Retirement Joint Proposal Application; (6) the pending PCIA reform proceeding at the Commission; and (7) the pending implementation of Procurement Expenditure Limitation ("PEL").

2.1. Adoption of Senate Bill 100

On September 10, 2018, Governor Brown signed SB 100, known as the 100 Percent Clean Energy Act of 2018. SB 100 increases the statutory RPS requirements to 44 percent by the end of 2024; 52 percent by the end of 2027; and 60 percent by 2030 and thereafter. PG&E's quantitative analysis in this 2018 RPS Plan, including its RNS tables, reflect these increased targets. Separately, SB 100 adopts a statewide policy that 100 percent of California's retail sales must come from RPS-eligible and zero-carbon resources by 2045.

2.2. Adoption and Implementation of Senate Bill 350

On October 7, 2015, Governor Brown signed SB 350, known as the Clean Energy and Pollution Reduction Act of 2015. Among other provisions, SB 350 increased the RPS target from 33 percent in 2020 to 50 percent in 2030. On April 15, 2016, ALJ Simon issued a ruling to begin implementation of SB 350 provisions relating to RPS procurement, including establishing post-2020 compliance periods and making changes to the banking provisions and long-term procurement requirements.[15]

On December 15, 2016, the Commission adopted D.16-12-040, which implements the new compliance periods and Procurement Quantity Requirements (“PQR”)[16] for the RPS Program as revised by SB 350.

On June 29, 2017, the Commission adopted D.17-06-026, which implements new compliance requirements for the California RPS program in response to changes made by SB 350. The Decision addresses the implementation of new rules for the use of long-term contracts in RPS compliance for all compliance periods beginning January 1, 2021. The new long-term requirement provides that, beginning January 1, 2021, at least 65 percent of the procurement a retail seller counts toward the RPS requirement of each compliance period must be from long term contracts. The Decision also: (1) implements new rules for applying excess procurement in one compliance period to later compliance periods beginning January 1, 2021; (2) provides direction for early compliance with the new long-term contract and excess procurement rules in the 2017-2020 compliance period; and (3) integrates changes made by SB 350 into the ongoing RPS compliance process.

In order to elect the early compliance option provided in SB 350, a retail seller must give notice of its election not later than 60 days from the effective date of D.17-06-026. PG&E gave notice on August 17, 2017, by letter addressed to the Director of Energy Division and served on the service list for R.15-02-020 of its election to comply early with the new long term and excess procurement requirements. Also in compliance with D.17-06-026, PG&E filed a motion on September 22, 2017 to update its RPS Procurement Plan to, among other things, reflect its election to comply early with

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15 *Administrative Law Judge’s Ruling Requesting Comments on Implementation of Elements of Senate Bill 350 Relating to Procurement under the California Renewables Portfolio Standard*, issued April 15, 2016.

16 As implemented by the Commission, a PQR is the total volume of RECs that a retail seller must retire for compliance with the RPS in each respective multi-year RPS compliance period.

the new long term and excess procurement requirements. Accordingly, the analysis set forth in the 2018 RPS Plan reflects PG&E's expectation that it will be subject to these new long term and excess banking rules beginning in the current 2017-2020 RPS compliance period.

On June 6, 2018, the Commission issued D.18-05-026, in which it implemented certain enforcement and penalty provisions contained in the SB 350 amendments to the RPS statute. Of particular relevance to this 2018 RPS Plan is the requirement in D.18-05-026 that each retail seller must annually demonstrate that transportation electrification is quantitatively accounted for in their RPS procurement plans. PG&E has described how it incorporated transportation electrification into its forecast of retail sales in Section 6.1.2.

Further Commission action on SB 350 implementation, as well as other remaining issues identified in R.15-02-020, may impact PG&E's procurement need and actions going forward.

2.3. Implementation of Mandated Procurement Programs

Existing mandated procurement programs for RPS-eligible resources include BioMAT, ReMAT, and PV RAM. As described below, PG&E continues to seek to procure resources under BioMAT despite a demonstrated lack of need for additional RPS resources. ReMAT has been suspended, and PG&E expects to complete its PV RAM program in 2018.

2.3.1. BioMAT

On September 27, 2012, SB 1122 was passed, requiring California's IOUs to procure a total of 250 megawatts ("MW") of new small-scale bioenergy projects that are 3 MW or less in size through the Feed-In Tariff ("FIT") Program; other Load Serving Entities ("LSE") (publicly-owned utilities), Electric Service Providers ("ESP"), CCAs) do not have this procurement obligation. Because all customers benefit equally from mandated procurement through BioMAT, all customers should contribute equitably to their costs. The total IOU mandate is allocated into three technology categories with separate MW targets: (1) 110 MW of biogas from wastewater plants and green waste; (2) 90 MW of dairy and other agriculture bioenergy; and (3) 50 MW of forest waste biomass. On December 18, 2014, the Commission issued D.14-12-081 to implement SB 1122, requiring the IOUs to file a tariff and contract for SB 1122 eligible generation. The IOUs filed their proposed contract and tariff on February 6, 2015, which were approved with modifications in D.15-09-004. PG&E's SB 1122 Program (BioMAT) began accepting participants on December 1, 2015 and the first program period (auction) was held on February 1, 2016. PG&E has held bimonthly BioMAT auctions since February 2016.

On October 28, 2016, the Commission issued D.16-10-025, which retained the current BioMAT pricing structure, clarified interconnection requirements, and ordered that the BioMAT sustainable forest management fuel use category (Category 3) include fuel obtained from high hazard zones). D.16-10-025 also amended eligibility requirements for interconnection and set monthly auctions for Category 3 projects.

On November 28, 2017, the Commission issued a letter setting a temporary price cap (which will be in place, pending the CPUC's review of the BioMAT program) for sustainable forest management projects at $199.72/megawatt-hours ("MWh") unless projects can attest to using 60% High Hazard Fuel. PG&E filed Advice Letter ("AL") 5285-E on May 2, 2018 making these program modifications. This advice letter was suspended on May 31, 2018 and as of August 5, 2018, PG&E is preparing to file a supplemental advice letter with minor modifications.

On December 6, 2017, the *Winding Creek Solar LLC v. Peeve*y court decision[17] found the ReMAT Program to violate the federal PURPA. The court found that ReMAT was non-compliant with PURPA because: (1) the price is not reflective of the Utility's avoided cost and (2) the program megawatt cap violates PURPA's must-take obligation. Given BioMAT has the same programmatic structure as ReMAT, PG&E refrained from

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17 *Winding Creek Solar Llc v. Peevey*, 293 F.Supp.3d 980 (N.D. CA 2017) (available at https://www.leagle.com/decision/infdco20171207935).

executing any BioMAT contracts until the CPUC addressed PG&E's concerns with the legality of the contracts in light of the *Winding Creek* court decision. On May 31, 2018, the Commission issued D.18-05-032, ordering the IOUs to modify the BioMAT contract to remove the representation that the contract does not violate any laws. As ordered by Resolution ("Res.") E-4922, PG&E executed the 10 outstanding Power Purchase Agreements ("PPA") (14.34 MW) on June 12, 2018, which included the modifications ordered in D.18-05-032. PG&E also filed a Tier 1 Advice Letter on June 21, 2018 acknowledging the execution of these contracts and the removal of the "any laws" language in those contracts. Outside of the temporary hold on executing BioMAT PPAs prior to June 12, 2018, the BioMAT program continues to operate and seek new procurement.

On a parallel track, the Commission issued D.17-08-021 instructing the IOUs to make changes to the PPA and tariff to reflect the ability for bioenergy facilities that are newly eligible with a nameplate capacity of up to 5 MW (per Assembly Bill ("AB") 1923) to be able to participate in the program. PG&E filed AL 5144-E-A with these changes, which the Commission approved on March 26, 2018.

On May 10, 2018, the Governor issued an Executive Order B-52-18[18] related to wildfire risk and the improvement of forest management and restoration. Item 16 requests that the Commission review and update its procurement programs for small bioenergy renewable generators.

2.3.2. ReMAT

ReMAT was established in May 2012 when the Commission made several revisions to its FIT program. These changes included increasing the eligible project size from 1.5 MW to 3 MW, establishing a 750 MW program cap, and adopting the

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18 Executive Order B-52-18 of Governor Edmund G. Brown, Jr., May 10, 2018 (available at https://www.gov.ca.gov/wp-content/uploads/2018/05/5.10.18-Forest-EO.pdf).

ReMAT pricing mechanism.[19] IOUs and publicly owned electric utilities were allocated a share of the 750 MW program cap; other LSEs (ESPs and CCAs) do not have this procurement obligation. Because all customers benefit equally from the mandated procurement through ReMAT, all customers should contribute equitably to their costs. PG&E has held bi-monthly auctions for ReMAT resources since November 1, 2013.

On December 6, 2017, the Winding Creek Solar LLC v. Peevey court decision[20] found the ReMAT Program to violate the federal PURPA. The court found that ReMAT was non-compliant with PURPA because: (1) the price is not reflective of avoided cost and (2) the program MW cap violates PURPA's must-take obligation. On December 5, 2017, the Executive Director of the CPUC issued a letter ordering the three IOUs to refrain from signing new ReMAT contracts, suspend holding any ReMAT program periods, and to stop accepting new applications for the program. As a result, all ReMAT program activity is currently on hold.

2.3.3. PV Program Procurement Through RAM (PV RAM)

In D.14-11-042, the Commission granted PG&E's petition to transfer approximately 200 MW from PG&E's PV Program to the Renewable Auction Mechanism 6 solicitation and two additional solicitations. On July 24, 2018, PG&E submitted AL 5330-E to the Commission, seeking approval for a PPA that would meet the final remaining procurement obligation pursuant to the original PV Program.

2.4. Coordination With the Integrated Resource Planning Process

In February 2018, the Commission issued D.18-02-018, which identified the CPUC's Reference System Plan using the RESOLVE model to determine the optimal California Independent System Operator ("CAISO")-wide portfolio of resources to meets the State's policy goals of achieving a 40 percent reduction in Greenhouse Gas ("GHG")

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19 See D.12-05-035, *Decision Revising Feed-in-Tariff Program, Implementing Amendments to Public Utilities Code Section 399.20 Enacted by Senate Bill 380, Senate Bill 32, and Senate Bill 2 1X and Denying Petitions for Modification of Decision 07-07-027 by Sustainable Conservation and Solutions for Utilities, Inc.*, issued May 31, 2012.

20 https://www.leagle.com/decision/infdco20171207935.

emissions below 1990 levels by 2030, a 50 percent RPS mandate by 2030, and adequate resources to ensure system reliability requirements. D.18-02-018 also set the guidelines for LSEs to determine their own IRPs, allowing use of either the IRP's GHG planning price or a mass-based LSE GHG target. On August 1, 2018, PG&E filed its IRP, containing a Preferred scenario based on its latest internal load forecast that showed it can comply with both the 50% RPS target as well as its LSE GHG target without the need for additional incremental renewable procurement.[21] This 2018 RPS Plan continues to model PG&E's RPS need based upon the existing statutory requirements, including the recently signed SB 100.

PG&E expects that outcomes from future IRP cycles will link more closely with resource-specific procurement processes and proceedings, such as the RPS Procurement Plan.[22] Going forward, PG&E supports close alignment between the IRP and the RPS proceeding, with the IRP comparing RPS resources against other GHG-free resources, including demand-side alternatives such as Energy Efficiency ("EE") and rooftop solar.

2.5. Diablo Canyon Retirement Joint Proposal Application

On August 11, 2016, PG&E and the Joint Parties[23] filed an Application requesting Commission approval of the retirement of Diablo Canyon nuclear power plant. In the Joint Proposal, PG&E proposed to adopt a voluntary 55 percent RPS

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21 As stated in its 2018 IRP, PG&E has no incremental procurement need for new RPS or GHG-free resources through 2030; PG&E can meet its 2030 GHG planning target with its existing GHG-free resource portfolio and resources added to comply with existing mandates.

22 Modeled results shown in this RPS Plan are generally consistent with PG&E's 2018 IRP except that the RPS Plan reflects minor updates to PG&E's RPS generation portfolio and includes some stochastically simulated results that are inherently variable.

23 Friends of the Earth, Natural Resources Defense Council, Environment California, International Brotherhood of Electrical Workers Local 1245, Coalition of California Utility Employees, and the Alliance for Nuclear Responsibility.

energy target beginning in 2031.[24] The Commission issued D.18-01-022 on January 16, 2018, approving PG&E's proposal to retire Diablo Canyon, stating the Commission's intent to avoid GHG emissions increase from Diablo Canyon's retirement, and that the need for replacement procurement should be addressed in the IRP proceeding. On September 19, 2018, Governor Brown signed SB 1090[25] that would, among other things, require the Commission to ensure the integrated resources plans avoid any increase in GHG emissions as a result of retiring the Diablo Canyon nuclear power plant.

2.6. Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the PCIA

The Commission issued an OIR to Review, Revise, and Consider Alternatives to the PCIA on June 29, 2017 (the PCIA OIR).[26] The PCIA OIR is a much-needed forum to address the broken, out-of-date system for allocating costs of long-term energy contracts and generation resource investments.

PG&E is committed to developing PCIA reform solutions that treat all customers fairly and equally, and that support California's clean energy goals. On April 2, 2018, the IOUs jointly filed testimony[27] in the PCIA OIR docket proposing a new PCIA methodology, which would involve the allocation of RECs to other parties. If the IOUs' proposed methodology, or a similar methodology, were approved by the Commission, that decision would affect PG&E's RPS compliance position and would cause PG&E to

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24 See A.16-08-006, Application of Pacific Gas and Electric Company for Approval of the Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, And Recovery of Associated Costs Through Proposed Ratemaking Mechanisms. The voluntary 55 percent by 2031 commitment in the Joint Proposal has recently been superseded by the higher statutory requirement of 60 percent by 2030 and thereafter. *See* SB 100, Stats. 2018, Ch. 312.

25 SB 1090, Stats. 2018, Ch. 561 (Monning).

26 See R.17-06-026.

27 See Joint IOU Prepared Testimony submitted in R. 17-06-026 on April 2, 2018 (available at http://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R1706026/1407/214907587.pdf).

procure additional RPS resources earlier than currently anticipated.[28] The Commission issued a PD and an alternate PD in the PCIA OIR in August 2018, and the earliest date on which the Commission may adopt a final decision is October 11, 2018.[29]

2.7. Cost Containment

In meeting its RPS requirements, PG&E has made every effort to procure least-cost and best-fit renewable resources. However, recognizing the potential cost impact that RPS procurement can have on customers, PG&E supports the establishment of a clear, stable, and meaningful Procurement Expenditure Limitation ("PEL") that both informs procurement planning and decisions, and promotes regulatory and market certainty. Implementation of the PEL has been pending at the Commission since SB 2 (1X) required the establishment of the PEL in 2011. PG&E urges the Commission to establish a PEL in order to protect customers from excessive costs, particularly from above-market, resource-specific RPS procurement mandates.

3. Assessment of RPS Portfolio Supplies and Demand

3.1. Supply and Demand to Determine the Optimal Mix of RPS Resources

Meeting California's RPS goals in a way that achieves the greatest value for customers continues to be a top priority for PG&E. In particular, PG&E continues to analyze its need to procure cost-effective resources that will enable it to achieve and maintain California's RPS targets. Under existing law,[30] PG&E is required through 2030 to retire sufficient numbers of RECs from RPS-eligible products to meet the following RPS requirements:

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28 See PG&E's 2018 Integrated Resource Plan, Alternative Scenario beginning on Page 63 (available at http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=511341).

29 McKinney, Jeanne "Re: Rulemaking 17-06-026 - Courtesy Notice" September 24, 2018. Email.

30 PG&E is assuming, for purposes of this 2018 RPS Plan, that the Commission will implement the SB 100 revised targets in the same "straight-line" manner as it implemented prior versions of the statutory RPS targets.

- 2017-2020 (Third Compliance Period): A percentage of the combined bundled retail sales that is consistent with the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail sales);
- 2021-2024: A percentage of the combined bundled retail sales that is consistent with the following formula: (.358 * 2021 retail sales) + (.385 * 2022 retail sales) + (.413 * 2023 retail sales) + (.44 * 2024 retail sales);[31]
- 2025-2027: (.467 * 2025 retail sales) + (.493 * 2026 retail sales) + (.52 * 2027 retail sales); and
- 2028-2030: (.547 * 2028 retail sales) + (.573 * 2029 retail sales) + (.60 * 2030 retail sales).

Based on preliminary results presented in Appendix A.2, PG&E delivered 33.0 percent of its power from RPS-eligible renewable sources in 2017.

As described more fully in Section 8 and reported in the current RNS calculations in Appendix A.2, based on forecasts and expectations of the ability of contracted resources to deliver, PG&E is well-positioned to meet its RPS compliance requirements through compliance period ("CP 5") (2025-2027). Under the 60 percent RPS by 2030 target, 60 percent RPS annually thereafter PG&E projects that it will not have incremental RPS physical need until 2026, and a procurement need beginning after 2033, after applying the Bank beginning in 2026. PG&E's RPS position will be updated annually to reflect any sales of RPS volumes.

3.2. Supply

3.2.1. Existing Portfolio

PG&E's existing RPS portfolio is comprised of a variety of technologies, project sizes, and contract types. The portfolio includes approximately 8,000 MW of projects online or under development, ranging from the following: (a) utility-owned solar and small hydro generation; (b) long-term RPS contracts for large wind, geothermal, solar,

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31 Compliance period requirements in 2021 and after are based on D.16-12-040, issued by the CPUC on December 20, 2016, which implemented the new compliance periods and PQR established pursuant to SB 350.

and biomass generation; and (c) small FIT contracts for solar PV, biogas, and biomass generation. This robust and diversified supply provides a solid foundation for meeting current and future compliance needs; however, the portfolio is also subject to uncertainties as discussed below and in more detail in Sections 7 and 8.

As described in further detail in Section 7.2, to model the project failure variability inherent in project development, PG&E assumes that project viability for a to-be-built project is a function of the number of years until its contract start date. This success rate is evolving and highly dependent on the nature of PG&E's portfolio, the general conditions in the renewable energy industry, and the timing of the RPS Plan publication date relative to recent project terminations.

Consistent with the project trends reported in its 2017 RPS Plan, PG&E has observed continued progress of key projects under development in its portfolio. Tax incentives (e.g., the federal Investment Tax Credit ("ITC") and Production Tax Credit ("PTC")) have helped the development of the market for renewables. PG&E expects renewables to continue to be cost-competitive in the future, whether or not the ITC and PTC are extended. Progress in the siting and permitting of projects also has supported PG&E's sustained high success rate. As described in more detail in this section, PG&E believes the renewable development market has stabilized for the near-term and the renewable project financing sector will continue to evolve well into the future.

Notwithstanding these positive trends, the timely development of renewable energy facilities remains subject to many uncertainties and risks, including regulatory and legal uncertainties, permitting and siting issues, technology viability, adequate fuel supply, and the construction of sufficient transmission capacity. These challenges and risks are described in more detail in the remainder of Section 3.

For purposes of calculating its demand for RPS-eligible products through the modeling described in Section 7, PG&E does not assume that expiring RPS-eligible contracts in its existing portfolio are re-contracted.

3.2.2. Impact of Green Tariff Shared Renewables Program

In 2013, SB 43 enacted the GTSR Program allowing PG&E customers to meet up to 100 percent of their energy usage with generation from eligible renewable energy resources. On January 29, 2015, the Commission issued D.15-01-051 implementing a GTSR framework, approving the IOUs' applications with modifications, and requiring the IOUs to begin procurement for the GTSR Program in advance of customer enrollment. In January 2016, PG&E's GTSR Program opened for enrollment under the program name "PG&E's Solar Choice." The most recent GTSR Annual Report for the program was filed with the Commission on March 15, 2018.

The GTSR Program impacts PG&E's RPS position in two ways: (1) PG&E's RPS supply may be affected as described below; and (2) retail sales will be reduced corresponding to program participation. D.15-01-051 permits the IOUs to supply Green Tariff customers from an interim pool of existing RPS resources until new dedicated Green Tariff projects come online. Generation from these interim facilities would no longer be counted toward PG&E's RPS targets, which will result in a decrease in PG&E's RPS supply. However, there is also a possibility that PG&E's RPS supply could increase in the future if generation from Green Tariff dedicated projects exceeds the demand of Green Tariff customers. In this case, those volumes procured for GTSR would then be added to PG&E's RPS portfolio, even if PG&E had no RPS need. PG&E has developed tracking and reporting protocols for tracking RECs transferred to and from the RPS portfolio and Green Tariff Programs.

In conformance with D.15-01-051[32] and as described in the Joint Procurement Implementation Advice Letter, PG&E reports annually on the amount of generation transferred between the RPS and GTSR Programs in a report that is filed by September 1 each calendar year. PG&E filed its first Annual GTSR Tracking Report on August 30, 2016, reporting that no generation transferred between the RPS and GTSR Programs in program year 2015. The second report that included generation transfer

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32 *See* D.15-01-051, p. 50.

between the RPS and GTSR programs was filed for program year 2016 on September 1, 2017. The third-generation transfer report for program year 2017 will be filed by September 1, 2018. In both 2016 and 2017, the sales of solar electricity under PG&E's Solar Choice Program were covered by the interim pool of existing solar resources from the RPS program; hence, the generation transfer occurred from the RPS program to the Solar Choice program. As described above, starting in 2018, the sales under the Solar Choice program will be covered by the PG&E's Solar Choice Program dedicated resources procured specifically for the Program. As more capacity was procured under the program than is currently needed for Solar Choice customers, generation will be transferred from the PG&E's Solar Choice Program to the RPS program in 2018.

For purposes of this 2018 RPS Plan, PG&E updated the RNS calculations to reflect expected GTSR Program impacts on retail sales and RPS supply through 2036.

3.2.3. RPS Market Trends and Lessons Learned

As its renewable resource portfolio has expanded to meet RPS goals, PG&E's procurement strategy has evolved. PG&E's strategy continues to focus on the following four key goals: (1) reaching, and sustaining, the existing RPS targets; (2) minimizing customer cost within an acceptable level of risk; (3) ensuring PG&E maintains an adequate Bank of surplus RPS volumes to manage annual load and generation uncertainty; and (4) aligning PG&E's RPS portfolio to its customers' needs. PG&E is continually adapting its strategy to accommodate new emerging trends in the California renewable energy market and regulatory landscape.

The California renewable energy market has developed and evolved significantly over the past few years. The market now offers a variety of technologies at generally lower prices than seen in earlier years of the RPS Program. The share of these technologies in PG&E's portfolio is changing as a result. For some technologies, such as PV, prices have dropped significantly due to various factors including technological breakthroughs, government incentives, and improving economies of scale as more projects come online.

Another trend, driven by the growth of renewable resources in the CAISO system, is the downward movement of mid-day wholesale energy market prices. Many renewable energy project types have minimal operating costs, and therefore additions of these renewables tend to move wholesale energy market clearing prices down. This has led to a change in the energy values associated with RPS offers, with decreasing value for renewable projects that generate during mid-day hours.

The growth of renewable resources also has produced challenges, such as negative wholesale energy market prices. Provisions that provide PG&E with greater flexibility to economically bid RPS-eligible resources into the CAISO markets are critical to helping address negative pricing situations that are likely to increase in the future. These provisions have customer benefits. Economic bidding enables RPS-eligible resource generation to be curtailed during negative pricing intervals when it is economic to do so, which protects customers from higher costs. Economic curtailment is discussed in greater detail in Section 12.

3.3. Demand

PG&E's demand for RPS-eligible resources is a function of multiple complex factors including regulatory requirements and portfolio considerations. Key RPS compliance requirements were established in D.11-12-020, D.12-06-038, and D.16-12-040. These requirements will need to be implemented by the Commission to incorporate the revised statutory RPS targets in the recently enacted SB 100.

One RPS compliance criterion of particular importance is that involving the need to ensure a balanced RPS portfolio. Implementing Section 399.16 of the Public Utilities Code ("Pub. Util. Code"), the Commission issued D.11-12-052 to define three statutory portfolio content categories ("PCC") of RPS-eligible products that retail sellers may use for RPS compliance, which impacts PG&E's demand for different types of RPS-eligible products. The ultimate effect of these portfolio balancing requirements is to significantly increase the demand of LSEs, including PG&E, for resources that are directly interconnected or deliver in real time to a California Balancing Area like CAISO.

Finally, PG&E's demand is a function of the risk factors discussed in more detail in Section 6; in particular, uncertainty regarding bundled retail sales can have a major impact on PG&E's demand for RPS resources, as further detailed below.

3.3.1. Near-Term Need for RPS Resources

Because PG&E has no incremental procurement need until after 2033 under existing RPS requirements, PG&E is proposing to not hold an RPS solicitation for the solicitation cycle for the year 2019. PG&E has sufficient time in the coming years to respond to changing market, load forecast, or regulatory conditions and will reassess the need for future Request for Offers ("RFO") in next year's RPS Plan. Although many factors could change PG&E's RPS compliance position, PG&E believes that its existing portfolio of executed RPS-eligible contracts, its owned RPS-eligible generation, and its expected Bank balances will be adequate to ensure compliance with near-term RPS requirements. Additionally, PG&E expects to continue procurement of additional volumes of incremental RPS-eligible contracts in 2019 through mandated procurement programs, such as the PV RAM and BioMAT Programs. PG&E will seek permission from the Commission should PG&E intend to procure any incremental RPS volumes other than amounts separately mandated by the Commission during the time period covered by the 2018 RPS Plan.

3.3.2. Portfolio Considerations

One of the most important portfolio considerations for PG&E is the forecast of bundled load. Currently, PG&E is projecting a decrease in retail sales in 2018 and a continued retail sales decrease through 2025, followed by modest growth thereafter. These changes are driven by the increasing impacts of EE, customer-sited generation, and CCA participation levels, and are offset slightly by an improving economy and growing electrification of the transportation sector. As described in more detail in

Section 7.2.1, PG&E uses its stochastic model to simulate a range of potential retail sales forecasts.

In addition to retail sales forecasts, as discussed in Sections 7, 8 and 9, PG&E's long-term demand for new RPS-eligible project deliveries is driven by: (1) PG&E's current projection of the success rate for its existing RPS portfolio, which PG&E uses to establish a minimum margin of procurement; and (2) the need to account for PG&E's risk-adjusted need, including any Voluntary Margin of Procurement ("VMOP") as determined by PG&E's stochastic model. The risk and uncertainties that justify the need for VMOP are further detailed and quantified in Sections 7 and 8.

3.4. Anticipated Renewable Energy Technologies and Alignment of PG&E's Portfolio With Expected Load Curves and Durations

PG&E's procurement evaluation methodology considers both market value and the portfolio fit of RPS-eligible resources in order to determine PG&E's optimal renewables product mix. With the exception of specific Commission-mandated programs and the PV Program, PG&E does not identify specific renewable energy technologies or product types (e.g., baseload, peaking as-available, or non-peaking as-available) that it is seeking to align, or fit, with specific needs in its portfolio. Instead, PG&E identifies an RPS-eligible energy need in order to fill an aggregate open position identified in its planning horizon and selects project offers that are best positioned to meet PG&E's current portfolio needs. This is evaluated through the use of PG&E's Portfolio Adjusted Value ("PAV") methodology, which ensures that the procured renewable energy products provide the best fit for PG&E's portfolio at the least cost. Starting with its 2014 RPS RFO, PG&E began utilizing the interim integration cost adder to accurately capture the impact of intermittent resources on PG&E's portfolio

3.5. RPS Portfolio Diversity

PG&E's RPS portfolio contains a diverse set of technologies, including PV, solar thermal, wind, small hydro, bioenergy, and geothermal projects in a variety of geographies, both in-state and out-of-state. PG&E's procurement strategy addresses technology and geographic diversity on a quantitative and qualitative basis.

In the Net Market Value ("NMV") valuation process, PG&E models the location-specific marginal energy and capacity values of a resource based on its forecasted generation profile. Thus, if a given technology or geography becomes "saturated" in the market, then those projects will see declining energy and capacity values in their NMV. This aspect of PG&E's valuation methodology should result in PG&E procuring a diverse resource mix if technological or geographic area concentration is strong enough to change the relative value of different resource types or areas. In addition, technology and geographic diversity may have the potential to reduce integration challenges. PG&E's use of the integration cost adder in its NMV valuation process may also result in the procurement of different technology types.

Diversity is also considered qualitatively when making procurement decisions. Resource diversity may decrease risk to PG&E's RPS portfolio given uncertainty in future hourly and locational market prices as well as technology-specific development risks.

PG&E recognizes that resource diversity is one option to minimize the overgeneration and integration costs associated with technological or geographic concentration. PG&E believes, as a general principle, that less restrictive procurement structures, in contrast to mandated programs, will provide the best opportunity to maximize value for its customers. Less restrictive procurement structures also will enable proper responses to changing market conditions and more competition between resources. PG&E further believes that geographic or technology-specific mandates add additional costs to RPS procurement.

3.6. Optimizing Cost, Value, and Risk for the Ratepayer

The costs of the RPS Program are becoming more apparent on customer bills as RPS projects have come online in significant quantities. In addition to cost impacts resulting from the direct procurement of renewable resources, customer costs are also impacted by the associated indirect incremental transmission and integration costs.

PG&E is aware of these direct and indirect cost impacts and will attempt to mitigate them whenever possible. PG&E's fundamental strategy for mitigating RPS cost impacts is to balance the opposing objectives of: (1) delaying additional RPS-related costs until deliveries are needed to meet compliance requirements; (2) managing the risk of being caught in a "seller's market," where PG&E faces potentially high market prices in order to meet near-term compliance deadlines, and (3) selling renewables in accordance with its framework described in Appendix G. When these objectives are combined with the general need to manage overall RPS portfolio volatility based on demand and generation uncertainty, PG&E believes it is prudent and necessary to maintain an adequate Bank through the most cost-effective means available.[33]

In addition, PG&E seeks to minimize the overall cost impact of renewables over time through promoting competitive processes that can encourage price discipline, and using the Bank to mitigate risks associated with load uncertainty, project failure, and generation variability. PG&E generally supports the use of competitive procurement mechanisms that are open to all RPS-eligible technologies and project sizes. As described in greater detail in Section 13, the cost impacts of mandated procurement programs that focus on particular technologies or project sizes may increase the overall costs of PG&E's RPS portfolio for customers as procurement from these programs comprise a larger share of PG&E's incremental procurement goals. This further underscores the need to implement an RPS cost containment mechanism that provides a cap on costs. PG&E supports a technology-neutral procurement process where all technologies can compete to offer the best value to customers at the lowest cost. Finally, as described in Sections 4 and 10, as part of its overall RPS position and management strategy, and with the goal of increasing cost-effectiveness, PG&E is

33 When considering sales, PG&E considers selling its entire historical long position (including any calculated minimum bank) if its future need is beyond five years.

proposing updates to its previously-approved framework for the sale of RPS volumes that returns revenue from sales to its customers.

3.7. Long-Term RPS Optimization Strategy

PG&E's long-term optimization strategy seeks to both achieve and maintain RPS compliance through and beyond 2030 and to minimize customer cost within an acceptable level of risk. Although PG&E remains mindful of meeting near-term compliance targets, it also seeks to refine strategies for maintaining compliance in a least-cost manner in the long-term (i.e., post-2030). PG&E's optimization strategy includes an assessment of compliance risks and approaches to protect against such risks by maintaining a Bank that is both prudent and needed to achieve the RPS compliance requirements. PG&E employs two models in order to optimize cost, value, and risk for the ratepayer while achieving sustained RPS compliance. This optimization analysis results in PG&E's "stochastically-optimized net short" ("SONS"), which PG&E uses to guide its procurement strategy, as further described in Sections 7 and 8.

PG&E's long-term optimization strategy includes three primary components: (1) incremental procurement (if needed); (2) possible sales of surplus procurement; and (3) effective use of the Bank. Although PG&E is proposing to not hold a 2018 RPS procurement solicitation, future incremental procurement aimed at avoiding the need to procure extremely large volumes in any single year remains a component of PG&E's long-term RPS optimization strategy. In addition to procurement, PG&E's optimization strategy includes sales of surplus procurement that provide a value to customers. PG&E has developed a framework for sales, which was approved in previous iterations by the CPUC, and is provided in Appendix G.

The third component of the optimization strategy is effective use of the Bank. Under the existing RPS targets and current market assumptions, PG&E plans to apply a portion of its projected Bank to meet compliance requirements beginning in 2026. Additionally, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in PG&E's stochastic model, while maintaining a minimum Bank size of at least [redacted]. Section 8 below provides additional information regarding the use and size of PG&E's Bank.[34]

4. RPS Position Management and Sales of RPS Products

As described in Section 8.2, PG&E forecasts its cumulative Bank to exceed the calculated minimum Bank size over the next 10 years, in part due to dramatic recent and ongoing changes to PG&E's retail sales forecast. Accordingly, PG&E continues to seek authority in this 2018 RPS Plan to sell RPS volumes from its portfolio through short-term sales under the updated RPS Sales Framework in Appendix G, and long-term sales in Section 4.4 as described below.

4.1. Updates to the RPS Sales Framework

The goal of PG&E's RPS Sales Framework is to prudently manage its portfolio with a focus on customer affordability, while continuing to maintain compliance with the RPS Program. PG&E will continue to seek and evaluate opportunities to execute short-term contracts to sell RPS-eligible products from its portfolio under the sales framework. These short-term sales would be for volumes to be delivered in the years 2019-2023, or through the year 2020 until after Phase 2 of the PCIA OIR is resolved, depending on the outcome in that proceeding.

The overall intent of PG&E's proposed changes to its RPS Sales Framework in this 2018 RPS Plan is to further the approved Framework's objectives of maximizing value for customers while maintaining compliance with RPS requirements. The updated framework would allow for the potential of significantly higher volumes of sales than were historically executed [redacted]. Under the Sales Framework in Appendix G, PG&E will establish an amount of gross volumes available for sale, with flexible sales quantities to be sold based on market pricing.

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34 *Ibid.*

The objective of PG&E's updated Sales Framework is to return to a balanced RPS position in a timely manner, and mitigate price risk to customers, by adhering to the following principles:

- Compliance: Ensure PG&E can maintain compliance with RPS requirements;
- Value for Customers: Ensure value for customers [redacted]; and
- Flexibility: Adapt to a fluctuating market and policy landscape through annual revisions in the RPS Plan filing.

In comparison to the approved 2017 RPS Sales Framework, PG&E is proposing several refinements aimed at simplifying the implementation process, maximizing revenue for customers, and balancing PG&E's RPS position, which has lengthened due to current and forecasted CCA departure and the high viability of projects in PG&E's existing portfolio. Below are the main refinements PG&E is proposing:

- [redacted][35] [redacted]

35 As an illustrative example, a total volume limit of 100,000 GWh divided by 20 years is 5,000 GWh. The total divided by 25 years is 4,000 GWh.

[redacted]

- [redacted]
- [redacted]

[redacted]

4.2. Implications of the Updated Sales Framework

A key aspect of the updated RPS Sales Framework is that it may result in volumes of sales significantly higher than the approximately 2,000 GWh forecasted in its RNS table, if there is sufficient market demand. Specifically, under a high demand scenario, PG&E could sell [redacted]

[redacted]. Additionally, even if the market demand is sufficient to sustain adequate prices to sell volumes of RPS products at the high end of the RPS Sales Framework, PG&E will be able to utilize volumes accumulated in its historical long position to satisfy its compliance obligations.

This is consistent with PG&E's overarching strategy to optimize its RPS position by using its historical long position to minimize customer costs while maintaining RPS compliance. Given that volumes in PG&E's historical long position have more value if PG&E retires them for RPS compliance than if they are sold into the market (since the PCC 1 or PCC 0 RECs in PG&E's Bank would become PCC 3 products when sold as unbundled RECs and used by a third-party for RPS compliance), it is prudent for PG&E to preserve the higher compliance value of its historical long position by selling future deliveries of bundled RPS products to third parties. This may cause PG&E's physical deliveries in a given year to fall below the RPS interim target or multi-year compliance period requirements, in which case PG&E will use volumes in its historical long position to meet compliance requirements. [redacted]

[redacted] [36] [redacted] These percentages represent a book-end scenario; actual sales and the resulting physical RPS position in

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36 [redacted]

these years will depend on market demand, fluctuations in load, and fluctuations in the output of the RPS contracts in PG&E's portfolio.

4.3. Implementation of the RPS Sales Framework

Based on current inputs to the framework described in Appendix G, PG&E will target issuing three, with a minimum of two, solicitations for the sale of bankable, bundled renewable generation and RECs in 2019.[37] PG&E anticipates selling short-term products (meaning contracts of five years or less in duration) based on its position.

PG&E intends to execute sales through PG&E-initiated solicitations. Confidential Appendix F contains PG&E's sales solicitation protocol and pro forma sales agreement. The pro forma sales agreement is largely unchanged from the 2018 Bundled RPS Energy Sale Short Form Confirm approved in the 2017 RPS Plan cycle. The final protocol represents a streamlined approach to selling RPS energy, with the primary selection criterion being price. As discussed in Section 10.4 below, PG&E anticipates minimal discussions with buyers with respect to the form agreement.

PG&E will file short-term sales agreements resulting from a solicitation that are negotiated based upon the pro forma sales agreement, with any necessary modifications, as Tier 1 Advice Letters for Commission approval.[38]

4.4. Long-Term Sales

PG&E may hold at least one solicitation for long-term sales in the future after Phase 2 of the PCIA OIR is resolved, depending on the outcome in that proceeding. Offering long-term sales allows PG&E to offer its RPS products to a broader market. Additionally, it provides PG&E an opportunity to gauge demand for long-term products. To ensure that PG&E does not exceed the total volumes that it may sell under the RPS Sales Framework, the proposed updated RPS Sales Framework will consider volumes to be offered for long-term sales, ensuring these volumes are not sold as part of the

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37 PG&E may issue more than three solicitations per year. The exact timing and number of solicitations will depend on the outcome of prior solicitations and/or changes to PG&E's RPS position.

38 D.17-12-007, OP 7; D.14-11-042, p. 77.

short-term sale solicitations. PG&E is reserving the amount described in Confidential Appendix G for long-term offers because: (1) it is unclear if a robust market exists for long-term sales; (2) it is unclear if the market values long-term products more than short term products; and (3) selling too much long-term product could impact PG&E's ability to comply with policy changes in the future that cause an incremental need for that long-term volume. PG&E will file any executed long-term RPS sales agreements for Commission approval through an Application after Phase 2 of the PCIA OIR is resolved, depending on the outcome in that proceeding.

5. Project Development Status Update

PG&E, Southern California Edison Company, and San Diego Gas & Electric Company file monthly RPS Database submissions with the CPUC. These monthly submissions contain a larger collection of data on each RPS project than previously provided in the IOUs' Project Development Status Reports. Project development status updates for RPS contracts can now be obtained from the publicly available data published on the Commission's website at http://cpuc.ca.gov/RPS_Reports_Data.

6. Potential Compliance Delays

This Section addresses factors, including those identified in the RPS statute, that may impact PG&E's ability to comply with its near-term RPS requirements or its need for a statutory waiver of those requirements.[39] While in general PG&E does not currently foresee obstacles to achieving compliance with existing RPS requirements, market conditions and changes in law and regulatory requirements could change this outlook in the future.

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39 This section is not intended to provide a detailed justification for an enforcement waiver or a reduction in the portfolio content requirements pursuant to Sections 399.15(b)(5) or 399.16(e). To the extent that PG&E finds that it must seek such a waiver or portfolio balance reduction in the future, it reserves the right to set forth a more complete statement, based upon the facts as they appear in the future, in the form of a petition or as an affirmative defense to any action by the Commission to enforce the RPS compliance requirements.

6.1. Consideration of Compliance Delay Risks in PG&E's RPS Strategy

Despite PG&E's current expectation that it will be able to comply on time with existing RPS requirements, significant market, operational, or regulatory changes could impact that assessment. This section describes briefly some of the risks and the steps PG&E is taking to mitigate these risks.

6.1.1. Curtailment of RPS Generating Resources

As discussed in more detail in Section 12, if RPS curtailed volumes increase substantially due to CAISO market or reliability conditions, curtailment may reduce the RPS energy available for compliance. In order to better address this challenge, PG&E's stochastic model incorporates estimated levels of curtailment, which enables PG&E to plan for appropriate levels of RPS procurement to meet RPS compliance even when volumes are curtailed. Additional detail on these assumptions is provided in Section 7.2.

6.1.2. Transportation Electrification

PG&E's retail sales forecast is adjusted for expected load increases due to plug-in electric vehicle ("EV") adoption. In order to consider the impact of EVs on PG&E's annual load, PG&E developed an internal probabilistic assessment of EV penetration, leveraging: (1) aggregated EV registration data available through summer 2017; (2) policy goals declared through summer 2017 as well as modeling of compliance for existing policy; (3) EV adoption scenarios developed by ICF International, Inc. in the California Electric Transportation Coalition's Transportation Electrification Assessment; and (4) inputs describing typical EV electricity consumption and charging behavior. PG&E did not directly leverage the California Energy Commission's ("CEC") 2017 Integrated Energy Policy Report ("IEPR") transportation electricity demand forecast in developing its EV forecast. PG&E and the CEC use two fundamentally different modelling approaches, with PG&E using a policy-driven adoption model (top down) and the CEC using a consumer choice model (bottom-up). Thus, modeling assumptions are not easily transferable between the two approaches. However, PG&E did compare its

EV forecast results against the CEC's results and found PG&E's forecast to be about 25% higher than the CEC forecast for PG&E's service territory in 2030. In addition to using different modeling approaches, PG&E and the CEC use different input assumptions that may impact the forecast results. For example, PG&E's EV forecast considers growth in the rideshare market, whereas the CEC IEPR forecast does not.

6.1.3. Risk-Adjusted Analysis

As more fully described in the following section, PG&E employs both a deterministic and stochastic approach to quantifying its remaining need for incremental renewable volumes. PG&E's experience with RPS procurement is that developers often experience difficulties managing some of the development issues described above. As described in Section 9, PG&E's expected RPS need calculation incorporates a minimum margin of procurement to account for some anticipated project failure and delays in PG&E's existing portfolio.

While it has made reasonable efforts to minimize risks of project delays or failures in an effort to comply with the 60 percent RPS Program procurement targets, PG&E cannot predict with certainty the circumstances—or the magnitude of the circumstances—that may arise in the future affecting the renewables market or individual project performance.

7. Risk Assessment

Dynamic risks, such as the factors discussed in Section 6 that could lead to potential compliance delays, directly affect PG&E's ability to plan for and meet compliance with the RPS requirements. As described elsewhere in this RPS Plan, PG&E is currently well-positioned to meet its RPS compliance requirements and its risk of non-compliance is low. Nevertheless, to account for these and additional uncertainties in future procurement, PG&E models the demand-side risk of retail sales uncertainty and the supply-side risks of generation variability, project failure, curtailment, and project delays in quantitative analyses.

Specifically, PG&E uses two approaches to modeling risk: (1) a deterministic model; and (2) a stochastic model. The deterministic model tracks the expected values of PG&E's RPS target and deliveries to calculate a "physical net short," which represents a point-estimate forecast of PG&E's RPS position and constitutes a reasonable minimum margin of procurement, as required by the RPS statute. These deterministic results serve as the primary inputs into the stochastic model. The stochastic model[40] accounts for additional compounded and interactive effects of various uncertain variables on PG&E's portfolio to suggest a procurement strategy at least cost within a designated level of non-compliance risk. The stochastic model provides target procurement volumes for each compliance period, which result in a designated Bank size for each compliance period. The Bank is then primarily utilized as VMOP to mitigate dynamic risks and uncertainties and ensure compliance with the RPS.[41]

This section describes in more detail PG&E's two approaches to risk mitigation and the specific risks modeled in each approach. Section 7.1 identifies the three risks accounted for in PG&E's deterministic model. Section 7.2 outlines the four additional risks accounted for in PG&E's stochastic model. Section 7.3 describes how the risks described in the first two sections are incorporated into both models, including details about how each model operates and the additional boundaries each sets on the risks. Section 7.4 notes how the two models help guide PG&E's optimization strategy and

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40 The stochastic model specifically employs both Monte Carlo simulation of risks and genetic algorithm optimization of procurement amounts. A Monte Carlo simulation is a computational algorithm commonly used to account for uncertainty in quantitative analysis and decision making. A Monte Carlo simulation provides a range of possible outcomes, the probabilities that they will occur and the distributions of possible outcome values. A genetic algorithm is a problem-solving process that mimics natural selection. That is, a range of inputs to an optimization problem are tried, one-by-one, in a way that moves the problem's solution in the desired direction—higher or lower—while meeting all constraints. Over successive iterations, the model "evolves" toward an optimal solution within the given constraints. In the case of PG&E's stochastic model, a genetic algorithm is employed to conduct a first-order optimization to ensure compliance at the identified risk threshold while minimizing cost.

41 PG&E has also developed a framework to assess whether to hold or sell RPS volumes, included in Appendix G.

procurement need. Section 8 discusses the results for both the deterministic and stochastic models and introduces the physical and optimized net short calculations presented in Appendices A.1 and A.2. Section 9 addresses PG&E's approach to the statutory minimum and voluntary margins of procurement.

7.1. Risks Accounted for in Deterministic Model

PG&E's deterministic approach models three key risks:

1) Standard Generation Variability: the assumed level of deliveries for categories of online RPS projects.

2) Project Failure: the determination of whether or not the contractual deliveries associated with a project in development should be excluded entirely from the forecast because of the project's relatively high risk of failure or delay.

3) Project Delay: the monitoring and adjustment of project start dates based on information provided by the counterparty (as long as deliveries commence within the allowed delay provisions in the contract).

The table below shows the methodology used to calculate each of these risks, and to which category of projects in PG&E's portfolio the risks apply. More detailed descriptions of each risk are described in the subsections below.

TABLE 7-1
DETERMINISTIC MODEL RISKS

Risk	Methodology	Applies to
Standard Generation Variability	• For non-QF projects executed post-2002, 100% of contracted volumes • For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries • Hydro QFs, Utility-Owned Generation ("UOG") and Irrigation District and Water Agency ("ID&WA") generation projections are updated to reflect the most recent hydro forecast.	Online Projects
Project Failure	• In Development projects with high likelihood of failure are labeled "OFF" (0% deliveries assumption) • All other In Development projects are "ON" (assume 100% of contracted delivery)	In Development Projects
Project Delay	• Professional judgment/Communication with counterparties	Under Construction Projects/ Under Development Projects/ Approved Mandated Programs

7.1.1. Standard Generation Variability

With respect to its operating projects, PG&E's forecast is divided into three categories: non- QF; non-hydro QFs; and hydro QF projects. The forecast for non-QF projects is based on contracted volumes. The forecast for non-hydro QFs is typically based on the average of the three most recent calendar year deliveries. The forecast for hydro QFs is typically based on historical production, normalized for average water year conditions, and then adjusted to reflect PG&E's latest internal hydro outlook. The UOG and ID&WA forecast are based on PG&E's latest internal hydro updates. Future years' hydro forecasts assume average water year production. These assumptions are included in this RPS Plan as Appendix D.

7.1.2. Project Failure

To account for the development risks associated with securing project siting, permitting, transmission, interconnection, and project financing, PG&E uses the data collected through PG&E's project monitoring activities in combination with best professional judgment to determine a given project's failure risk profile. PG&E

categorizes its portfolio of contracts for renewable projects into two risk categories: OFF (represented with 0 percent deliveries) and ON (represented with 100 percent deliveries). This approach reflects the reality of how a project reaches full development; either all of the generation from the project comes online, or none of the generation comes online.

1. **OFF/Closely Watched** – PG&E excludes deliveries from the "Closely Watched" projects in its portfolio when forecasting expected incremental need for renewable volumes. "Closely Watched" represents deliveries from projects experiencing considerable development challenges as well as once-operational projects that have ceased delivering and are unlikely to restart. In reviewing project development monitoring reports, and applying their best professional judgment, PG&E managers may consider the following factors when deciding whether to categorize a project as "Closely Watched":
    - Actual failure to meet significant contractual milestones (e.g., guaranteed construction start date, guaranteed commercial operation date, etc.);
    - Anticipated failure to meet significant contractual milestones due to the project's financing, permitting, and/or interconnection progress or to other challenges (as informed by project developers, permitting agencies, status of CAISO transmission studies or upgrades, expected interconnection timelines, and/or other sources of project development status data);
    - Significant regulatory contract approval delays (e.g., 12 months or more after filing) with no clear indication of eventual authorization;
    - Developer's statement that an amendment to the PPA is necessary in order to preserve the project's commercial viability;
    - Whether a PPA amendment has been executed but has not yet received regulatory approval; and
    - Knowledge that a plant has ceased operation or plant owner/operator's statement that a project is expected to cease operations.

Final forecasting assessments are project-specific and PG&E does not consider the criteria described above to be exclusive, exhaustive, or the sole criteria used to categorize a project as “Closely Watched.”[42] PG&E does not currently have any in-development projects categorized as “OFF” in its deterministic model.

2. **ON** – Projects in all other categories are assumed to deliver 100 percent of contracted generation over their respective terms. There are three main categories of these projects. The first category, which denotes projects that have achieved commercial operation or have officially begun construction, represents the majority of “ON” projects. Based on empirical experience and industry benchmarking, PG&E estimates that this population is highly likely to deliver. The second category of “ON” projects is comprised of those that are in development and are progressing with pre-construction development activities without foreseeable and significant delays. The third category of “ON” projects represents executed and future contracts from Commission-mandated programs. While there may be some risk to specific projects being successful, because these volumes are mandated, the expectation is that PG&E will replace failed volumes within a reasonable timeline.

7.1.3. Project Delay

Because significant project delays can impact the RNS, PG&E regularly monitors and updates the development status of RPS-eligible projects from PPA execution until commercial operation. Through periodic reporting, site visits, communication with counterparties, and other monitoring activities, PG&E tracks the progress of projects towards completion of major project milestones and develops estimates for the construction start (if applicable) and commercial operation of projects.

7.2. Risks Accounted for in Stochastic Model

The risk factors outlined in the deterministic model are inherently dynamic conditions that do not fully capture all of the risks affecting PG&E’s RPS position. Therefore, PG&E has developed a stochastic model to better account for the compounded and interactive effects of various uncertain variables on PG&E’s portfolio.

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42 For instance, PG&E may elect to count deliveries from projects that meet one or more of the criteria if it determines, based on its professional judgment, that the magnitude of challenges faced by the projects do not warrant exclusion from the deterministic forecast. Similarly, the evaluation criteria employed by PG&E could evolve as the nature of challenges faced by the renewable energy industry, or specific sectors of it, change.

PG&E's stochastic model assesses the impact of both demand- and-supply-side variables on PG&E's RPS position from the following four categories:

1) Retail Sales Uncertainty: This demand-side variable is one of the largest drivers of PG&E's RPS position;
2) Project Failure Variability: Considers additional project failure potential beyond the "on-off" approach in the deterministic model;
3) Curtailment: Considers buyer-ordered (economic), CAISO-ordered or Participating Transmission Owner ("PTO") -ordered curtailment; and
4) RPS Generation Variability: Considers additional RPS generation variability above and beyond the small percentages in the deterministic model.

When considering the impacts that these variables can have on its RPS position, PG&E organizes the impacts into two categories: (1) persistent across years; and (2) short-term (e.g., effects limited to an individual year and not highly correlated from year to year). Table 6-2 below lists the impacts by category, while showing the size of each variable's overall impact on PG&E's RPS position.

TABLE 7-2
CATEGORIZATION OF IMPACTS ON RPS POSITION

	Impact	Categorization
Higher Impact on RPS Position ↑	**1. Retail Sales Uncertainty:** Changes in retail sales tend to persist beyond the current year (e.g., economic growth, EE, CCA and DA, and distributed generation impacts).	**Variable and persistent** *(If an outcome occurs, the effect persists through more than one year).*
	2. Curtailment: Impact increases with higher penetration of renewables and will be persistent.	**Variable and persistent**
	3. RPS Generation Variability: Variability in yearly generation is largely an annual phenomenon that has little persistence across time.	**Variable and short-term** *(If an outcome occurs, the effect may only occur for the individual year.)*
↓ **Lower Impact on RPS Position**	**4. Project Failure Variability:** Lost volume from project failure persists through more than one year.	**Variable and persistent**

7.2.1. Retail Sales Variability

PG&E's retail sales are impacted by factors such as weather, economic growth or recession, technological change, EE, levels of Direct Access ("DA") and CCA participation, and distributed generation. PG&E generates a distribution of the bundled retail sales for each year using a model that simulates thousands of possible bundled load scenarios. Each scenario is based on regression models for load in each end use sector as a function of weather and economic conditions with consideration of future policy impacts on EE, EVs, and distributed generation.

As load loss due to DA is currently capped by California statute and cannot be expanded without additional legislation, PG&E is not forecasting increases in DA. Load loss due to CCA departure is modeled in two categories: (1) existing CCAs that have already departed or will depart and serve load by 2019; and (2) potential CCAs that have expressed interest in forming based on publicly available information. For existing CCAs, PG&E follows a meet and confer process to communicate with CCAs regarding their load forecasts. PG&E receives year-ahead load, peak demand, and customer forecasts from the CCAs, and grows these forecasts using PG&E's forecasted total system load growth rate, which accounts for economic/demographic factors, weather, and growth of DER technologies such as solar PV, EE. For potential CCAs, PG&E has developed a stochastic (probabilistic) approach to forecast CCA load departure. This model uses publicly available information—including feasibility studies, implementation plans, board meetings, and news articles—to assign probabilities to all communities considering CCA formation. Similar probabilities are applied to communities with the same CCA maturity levels. The model uses 2016 annual energy load as the benchmark, and PG&E applies system load growth percentages to approximate future load growth or decline. Appendix C.1 lists the resulting simulated retail sales and summary statistics for the period 2018-2030. Appendix C.5 shows the resulting simulated RPS target when accounting for the retail sales uncertainty for the period 2018-2030.

7.2.2. RPS Generation Variability

Based on analysis of historical hydro generation data from 1985-2012, wind generation data from 1985-2011, and generation data from solar and other technologies where available, PG&E estimated a historical annual variability measured by the coefficient of variation of each resource type. [redacted] Due to significant variability in annual precipitation, small hydro demonstrates the largest annual variability (coefficient of variation of [redacted]). The remaining resource types range in annual variability from [redacted] for biomass and geothermal, [redacted] for solar PV and solar thermal to [redacted] for wind. Collectively, technology diversity helps to reduce the overall variation, because variability around the mean is uncorrelated among technologies. Appendix C.3 lists the resulting simulated generation and summary statistics for the period 2018-2030.

To better understand the wide range of variability of the above risks and thus, the need for a stochastic model to optimize PG&E's procurement volumes, Appendix C.4 combines the Project Failure and RPS Generation Variability factors into a "total deliveries" probability distribution, and shows how these variables interact.

7.2.3. Curtailment

The stochastic model also estimates the potential for RPS curtailment. Curtailment can result from either buyer-ordered (economic), CAISO-ordered or PTO-ordered curtailment (the latter two driven by system stability issues, not economics). Curtailment forecasts ramp from a historical level of [redacted]

[redacted].[43] These modeling assumptions will not necessarily reflect the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. Please see Section 12 for more information regarding curtailment.

7.2.4. Project Failure Variability

To model the project failure variability inherent in project development, PG&E assumes that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. That is, a new project scheduled to commence deliveries to PG&E next year is considered more likely to be successful than a project scheduled to begin deliveries at a much later date. The underlying assumption is that both PG&E and the counterparty know more about a project's likelihood of success the closer the project is to its initial delivery date, and the counterparty may seek to amend or terminate a non-viable project before it breaches the PPA. Working from this assumption, PG&E assigns a probability of project success for new, yet-to-be-built projects equal to [redacted]. For example, a project scheduled to come online in five years or more is assumed to have a [redacted] percent chance of success. This success rate is based on experience and is reflective of higher project development success rates of PG&E's RPS portfolio in more recent years.

Although PG&E's current existing portfolio of projects may have higher rates of success, the actual success rate for projects in the long-term may be higher or lower. Appendix C.2 lists PG&E's simulated failure rate and summary statistics for the period 2017-2030.

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43 [redacted]

7.2.5. Comparison of Model Assumptions

Table 7-3 below shows a comparison of how PG&E's deterministic and stochastic models each handle uncertainty with regard to retail sales, project failure, RPS generation, and curtailment. Section 8 provides a more detailed summary of the results from PG&E's deterministic and stochastic modeling approaches.

TABLE 7-3
COMPARISON OF UNCERTAINTY ASSUMPTIONS
BETWEEN PG&E'S DETERMINISTIC AND STOCHASTIC MODELS

Uncertainty[(a)]	Deterministic Model	Stochastic Model
1) Retail Sales Variability	Uses most recent PG&E bundled retail sales forecast for next 5 years and 2014 Long-Term Procurement Plan ("LTPP") for later years (Appendix A.1); Uses most recent PG&E bundled retail sales forecast for all years (Appendix A.2).	Distribution based on most recent (2017) PG&E bundled retail sales forecast.
2) Project Failure Variability	Only turns "off" projects with high likelihood of failure per criteria. "On" projects assumed to deliver at Contract Quantity.	Uses [redacted] to model a success rate for all "on" yet-to-be-built projects in the deterministic model. Thus, for a project scheduled to come online in 5 years, the project success rate is [redacted]. This success rate is based on PG&E's experience that the further ahead in the future a project is scheduled to come online, the lower the likelihood of project success.
3) RPS Generation Variability	Non-QF projects executed post-2002, 100% of contracted volumes. For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries. Hydro QFs, UOG and ID&WA generation projections are updated to reflect the most recent hydro forecast.	Hydro: [redacted] annual variation Wind: [redacted] annual variation Solar: [redacted] annual variation Biomass and Geothermal: [redacted] annual variation
4) Curtailment	None	Curtailment is modeled as increasing between the following data points: [redacted] in 2017 [redacted] in 2020 [redacted] in 2024 [redacted] in 2030

(a) These modeling assumptions will not necessarily align with the future actual sales, project failure rates, RPS generation, and curtailment hours, but are helpful in terms of considering the impact of uncertainty on long-term RPS planning and compliance.

7.3. How Deterministic Approach Is Modeled

The deterministic model is a snapshot in time of PG&E's current and forecasted RPS position. The deterministic model relies on currently available generation data for executed online and in development RPS projects as well as PG&E's most recent bundled retail sales forecast. The results from the deterministic model determine PG&E's "physical net short," which represents the best current point-estimate forecast of PG&E's RPS position today. The deterministic model should not be seen as a static target because the inputs are updated as new information is received.

7.4. How Stochastic Approach Is Modeled

The stochastic model adds rigor to the risk-adjustment embedded in the deterministic model—using Monte Carlo simulation—and optimizes its results to achieve the lowest cost possible given a specified risk of non-compliance and the stochastic model's constraints.

The methodology for the stochastic model is as follows:

1) Create an optimization problem by establishing the (a) objectives; (b) inputs; and (c) constraints of the model:
   (a) The objective is to minimize procurement cost.
   (b) The inputs are a range of potential incremental RPS-eligible deliveries (new and re-contracted volumes)[44] in each year of the [redacted] timeframe. The potential incremental procurement is restricted to a range of no less than zero and no more than [redacted] annually.
   (c) The constraints are: (1) to keep PG&E's risk of non-compliance to less than [redacted], less than [redacted], less than [redacted]; and (2) to restrict PG&E's Bank over time to the size necessary to meet compliance objectives within the specified risk threshold.

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44 Although the physical net short calculations do not include any assumptions related to the re-contracting of expiring RPS-eligible contracts, this modeling approach assumes re-contracting will be considered in the future side-by-side with procurement of other new resources.

2) The stochastic model then solves the optimization problem by examining thousands of combinations of procurement need in each year. For each of these combinations, the model runs hundreds of iterations as part of its Monte Carlo simulation of uncertainty for each of the risk factors in the stochastic model to test if the constraints are met. If the solution for that combination of inputs fits within the given constraints, it is a valid outcome.
3) For each valid outcome, the mean Net Present Value ("NPV") cost of meeting that procurement need is calculated based on PG&E's RPS forward price curve.
4) Finally, the model sorts the NPV of the potential procurement outcomes from smallest to largest, thus showing the optimal RPS-eligible deliveries needed in the years [redacted] to ensure compliance based on the modeled assumptions.

The modeled solution becomes a critical input into PG&E's overall RPS optimization strategy, but the outputs are subject to further analysis based upon best professional judgment to determine whether factors outside the model could lead to better outcomes. For example, the model does not allow for price arbitrage through sales of RPS generation in the near-term and additional incremental procurement in the long-term. Nor does the model consider the opposite strategy of advance procurement of RPS-eligible products in 2018 for purposes of reselling those products in the future at a profit. As a general matter, PG&E does not approach RPS procurement and compliance as a speculative enterprise and so has not modeled or otherwise proposed such strategies in this 2018 RPS Plan.

7.5. Incorporation of the Above Risks in the Two Models Informs Procurement Need and Sales Opportunities

Incorporating inputs from the deterministic model, the stochastic model provides results that lead to a forecasted procurement need or SONS, expected Bank usage and thus an anticipated Bank size, for each compliance period. The SONS for the existing RPS targets are shown in Row La of PG&E's Alternate RNS in Appendix A.2.

The results of both the deterministic and stochastic models are discussed further in Section 8 and minimum margin of procurement is addressed in Section 9.

8. **Quantitative Information**

As discussed in Section 7, PG&E's objectives for this RPS Plan are to both achieve and maintain RPS compliance and to minimize customer cost within an acceptable level of risk. To do that, PG&E uses both deterministic and stochastic models. This section provides details on the results of both models and references RNS tables provided in Appendix A. Appendix A.1 presents the RNS in the form required by the ALJ's Ruling on RNS issued May 21, 2014 in R.11-05-005 ("ALJ RNS Ruling") and includes results from PG&E's deterministic model only, while Appendix A.2 is a modified version of Appendix A.1 to present results from both PG&E's deterministic and stochastic models. These modifications to the table are necessary in order for PG&E to adequately show its results from its stochastic optimization.

This section includes a discussion of PG&E's forecast of its Bank size and PG&E's analysis of the minimum bank needed.

8.1. Deterministic Model Results

Results from the deterministic model under a 60 percent by 2030 RPS target and 60 percent RPS annually thereafter are shown as the physical net short in Row Ga of Appendices A.1 and A.2. Appendix A.1 provides a physical net short calculation using PG&E's March 2018 internal Bundled Retail Sales Forecast for years 2018-2022 and the LTPP sales forecast for 2023-2036,[45] while Appendix A.2 relies exclusively on PG&E's March 2018 internal Bundled Retail Sales Forecast. Following the methodology described in Section 7.1, PG&E currently estimates a long-term volumetric success rate of 100 percent for its portfolio of executed-but-not-operational projects. The annual forecast failure rate used to determine the long-term volumetric success rate is shown in Row Fbb of Appendix A.2. This success rate is a snapshot in time and is also impacted by current conditions in the renewable energy industry, discussed in more detail in Section 6, as well as project-specific conditions. In addition to the current long-term volumetric success rate, Rows Ga and Gb of Appendix A.2 depict PG&E's

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[45] Bundled sales forecast used for 2023-2036 is from the Conforming Case in PG&E's 2018 LSE IRP filed for the 2017-2018 IRP Cycle.

expected compliance position using the current expected need scenario before application of the Bank.

8.2. Stochastic Model Results

This subsection describes the results from the stochastic model and the SONS calculation for the 60 percent RPS by 2030 target, and 60 percent RPS annually thereafter. Because PG&E uses its stochastic model and internal Bundled Retail Sales Forecast to inform its RPS procurement, PG&E has created an Alternate RNS in Appendix A.2 for the 60 percent RPS target. Appendix A.1 provides an incomplete representation of PG&E's optimized net short, as the formulas embedded in the RNS form required by the ALJ RNS Ruling do not enable PG&E to capture its stochastic modeling inputs and outputs. In Appendix A.2, two additional rows have been added. Rows Gd and Ge show the stochastically-adjusted net short, which incorporates the risks and uncertainties addressed in the stochastic model. This is prior to any applications of the Bank, but includes additional procurement needed for maintaining an optimized Bank size. Additionally, PG&E has modified the calculations in Rows La and Lb in order to more accurately represent PG&E's SONS.

Under the existing RPS targets, PG&E is well-positioned to meet its compliance period requirements through the fifth (2025-2027) compliance period. As shown in Row Lb of Appendix A.2, the stochastic model shows a third compliance period RPS position of [redacted], a fourth compliance period RPS position of [redacted], a fifth compliance period RPS position of [redacted], and a sixth compliance period RPS position of [redacted]. Appendix A.2 also shows a physical net short of approximately [redacted] beginning in 2026 (Row Ib plus Row Gd).

For both tables, Row Lb includes both PG&E's executed and generic RPS sales volumes shown in Rows Fd and Ib, respectively, and equates to 2,069 GWh per year of total RPS sales except for 2019.[46] The annual RPS sales volume forecast assumption

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[46] Total forecasted RPS sales in 2019 equals 4,729 GWh based on executed sale agreements through August 31, 2018.

is based on the actual RPS sales completed in 2017 and is included for RPS position planning purposes. Based on the sales framework approved in the 2017 RPS Plan, these volumes could potentially exceed [redacted] in any given year if [redacted]. Under the updated RPS Sales Framework proposed in Appendix G, annual sales volumes could be even greater depending on [redacted]. In the event that the total RPS generation less RPS sales falls below the RPS Compliance requirement in any given year, PG&E would still meet its RPS Compliance requirement through the use of previously accumulated RPS bank (see Row J in Appendix A.2).

8.2.1. Stochastically-Optimized Net Short to Meet Non-Compliance Risk Target

To evaluate possible procurement strategies, PG&E selected the following non-compliance risk targets for each future CP: [redacted]

Figure 8-1 shows the model's forecasted procurement need and resulting Bank usage under the 60 percent RPS by 2030 target and 60 percent RPS annually thereafter. Under this projection, a portion of the Bank is used to meet PG&E's compliance need beginning in 2026, the first year showing a stochastically-adjusted net short, and continuing throughout the decade, while reserving a portion of the Bank to be maintained as VMOP to manage risks discussed in Section 7. Appendix A.2 provides the detailed results. Annual forecasted Bank usage is shown as the sum of Rows Gd and Ib of this Appendix. After accounting for Bank usage, the first year of incremental procurement need is forecasted as after 2033. Should PG&E engage in additional RPS sales, this may result in an earlier procurement need year and its position will be updated in subsequent RPS Plans.

FIGURE 8-1
CONFIDENTIAL
STOCHASTIC RESULTS: EXPECTED BANK USAGE AND STOCHASTICALLY-OPTIMIZED NET SHORT

[redacted]

Note: Net short and bank usage values have been rounded to the nearest 100 GWh.

Because the stochastic model inputs change over time, these estimates should be seen as a snapshot in time rather than a static target and the procurement targets will be re-assessed as part of future RPS Plans.

8.2.2. Bank Size Forecasts and Results

Figure 8-2 shows PG&E's current and forecasted cumulative Bank from the first compliance period through 2033. PG&E's total Bank size as of the end of the second compliance period was approximately 12,800 GWh. The stochastic model's results currently project PG&E's Bank size to increase in the second through fifth compliance periods and gradually decrease over time to approximately [redacted] (as shown in Figure 8-2, as well as in Appendix A.2, Row J). As stated in Section 8.2 above, the forecasted 2033 Bank total assumes 2,069 GWh per year of RPS sales. Given the expected size of the Bank in 2030, PG&E is proposing a change to its RPS sales framework in order to increase the volumes available to sell during the period covered by this 2018 RPS Plan (see Section 4).

FIGURE 8-2
CONFIDENTIAL
STOCHASTIC RESULTS: EXPECTED CUMULATIVE BANK

[redacted]

Note 1: Bank values in CP1 and CP2 are based on the total 'Excess Procurement Bank' in PG&E's RPS Compliance Report.

Note 2: Bank values in CP3 and beyond have been rounded to the nearest 100 GWh.

There is a trade-off between non-compliance risk and Bank size. A larger Bank size decreases non-compliance risk. However, a larger Bank size may also increase procurement costs. Higher risk scenarios would result in a lower Bank size and, as discussed above, would increase PG&E's probability of being in a position in which PG&E might need to make unplanned purchases to comply with its RPS requirement. In that situation, PG&E might not be able to avoid higher procurement costs due to the potential for upward pressure on prices caused by the need for unplanned purchases. [redacted]

8.2.3. Minimum Bank Size

PG&E performed a simulation of variability in PG&E's future generation and RPS compliance targets over [redacted] years—i.e., the amount of the RPS generation ("delivery") net of RPS compliance targets ("target")—and found that a Bank size of at least [redacted] GWh is the minimum Bank necessary to maintain a cumulative non-compliance risk of no greater than [redacted].[47] The difference between delivery and target can be thought of as the potential "need" (if negative) or "surplus" (if positive) that PG&E has in any one year.

Figure 8-3 shows this distribution based on the deterministic procurement necessary to meet the expected RPS targets with expected generation during [redacted].

Based on current model assumptions and inputs, Figure 8-3 shows that approximately [redacted] of the time, PG&E would have a greater than [redacted] GWh deficit in meeting compliance for [redacted]. Thus, PG&E must maintain a Bank size higher than this amount to limit the risk of non-compliance to an acceptable level.[48]

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47 [redacted]

48 See Footnote 25.

FIGURE 8-3
CONFIDENTIAL
DISTRIBUTION OF DELIVERY MINUS TARGET FROM 2026 THROUGH 2030
UNDER A 60 PERCENT RPS TARGET

[redacted]

As stated in Section 8.2.2, the stochastic model's results show PG&E's forecasted [redacted]. PG&E's strategy is to maintain an adequate Bank in order to avoid the need to procure extremely large volumes in any single year to meet compliance needs.

Because the model inputs change over time, estimates of the Bank size resulting from the implementation of the procurement plan will also change. In practice, the actual outcome will more likely be a mix of factors both detracting from and contributing to meeting the target, which is what the probability distribution in Figure 8-3 illustrates.

8.3. Implications for Future Procurement

PG&E plans to continually refine both its deterministic and stochastic models, thus the procurement strategy outlined above is applicable to this 2018 RPS Plan only. In future years, PG&E's procurement strategy will likely change, based on updates to the data and algorithms in both models. Additionally, PG&E will continue to assess the value to its customers of sales. PG&E will update its physical RNS in future RPS Plans if it executes any such sale agreements.

9. **Margin of Procurement**

When analyzing its margin of procurement, PG&E considers two key components: (1) a statutory minimum margin of procurement to address some anticipated project failure or delay, for both existing projects and projects under contract but not yet online, that is accounted for in PG&E's deterministic model; and (2) a VMOP, which aims to mitigate the additional risks and uncertainties that are accounted for in PG&E's stochastic model. Specifically, PG&E's VMOP intends to: (a) mitigate risks associated with short-term variability in load; (b) protect against project failure or delay exceeding forecasts; and (c) manage variability from RPS resource generation. In so doing, PG&E's VMOP helps to eliminate the need at this time to procure long-term contracts above the 60 percent RPS target by creating a buffer that enables PG&E to manage the year-to-year variability that result from risks (a)-(c). This section discusses both of these components and how each is incorporated into PG&E's quantitative analysis of its RPS need.

9.1. Statutory Minimum Margin of Procurement

The RPS statute requires the Commission to adopt an "appropriate minimum margin of procurement above the minimum procurement level necessary to comply with the [RPS] to mitigate the risk that renewable projects planned or under contract are delayed or canceled."[49] PG&E's reasonableness in incorporating this statutory minimum margin of procurement into its RPS procurement strategy is one of the factors the Commission must consider if PG&E were to seek a waiver of RPS enforcement because conditions beyond PG&E's control prevented compliance.[50]

As described in more detail in Section 7, PG&E has developed its risk-adjusted RPS forecasts using a deterministic model that: (1) excludes volumes from contracts at risk of failure from PG&E's forecast of future deliveries; and (2) adjusts expected commencement of deliveries from contracts whose volumes are included in the model

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49 Cal. Pub. Util. Code § 399.13(a)(4)(D).

50 *Id.*, § 399.15(b)(5)(B)(iii).

(so long as deliveries commence within the allowed delay provisions in the contract). PG&E considers this deterministic result to be its current statutory margin of procurement.[51] However, as discussed in Sections 7 and 8, these results are variable and subject to change, and thus PG&E does not consider this statutory margin of procurement to sufficiently account for all of the risks and uncertainties that can cause substantial variation in PG&E's portfolio. To better account for these risks and uncertainties, PG&E uses its stochastic model to assess a VMOP, as described further below.

9.2. Voluntary Margin of Procurement

The RPS statute provides that in order to meet its compliance goals, an IOU may voluntarily propose a margin of procurement above the statutory minimum margin of procurement.[52] As discussed further in Sections 7 and 8, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model.

While PG&E's current optimization strategy projects the use of a portion of PG&E's projected Bank to meet compliance requirements in 2028 and beyond, PG&E believes it would be imprudent to use its entire projected Bank toward meeting its RPS compliance, rather than to cover unexpected demand and supply variability and project failure or delay exceeding forecasts from projects not yet under contract. When used as VMOP, holding a minimum Bank will reduce non-compliance risk, helping to avoid long-term over-compliance above the existing RPS targets and thus reducing long-term costs of the RPS Program. Since the model inputs change over time, estimates of the Bank and VMOP are not a static target and will change, so these estimates should be

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51 In the past PG&E has seen higher failure rates from its overall portfolio of executed-but-not-operational RPS contracts. However, as the renewables market has evolved—and projects are proposed to PG&E at more advanced stages of development—PG&E has observed a decrease in the expected failure rate of its overall portfolio. The more recent projects added to PG&E's portfolio appear to be significantly more viable than some of the early projects in the RPS Program, resulting in lower current projections of project failure than have been discussed in past policy forums.

52 Cal. Pub. Util. Code § 399.13(a)(4)(D).

seen as a snapshot in time. Additional discussion on the need for and use of the Bank and VMOP are included in Sections 7 and 8.

Additionally, as a portion of the Bank will be used as VMOP, PG&E will continue to reflect zero volumes in Row D of its RNS tables, consistent with how it has displayed the VMOP in past RNS tables.

10. **Bid Selection Protocol**

As described in Sections 3 and 8, PG&E is well positioned to meet its RPS targets until after 2033. As a result, PG&E proposes to not hold a 2019 RPS procurement solicitation. PG&E will continue to procure RPS-eligible resources in 2018 and 2019 through other Commission-mandated programs, such as the BioMAT and PV RAM programs. PG&E will seek permission from the Commission to procure any renewable energy amounts during the time period covered by the 2018 RPS Plan, except for RPS amounts that are separately mandated. Thus, PG&E is not including in the 2018 RPS Plan a solicitation protocol for procuring additional RPS resources.

Although PG&E is not planning for a RPS Solicitation, PG&E recognizes that the most recent detailed description of its least-cost, best-fit ("LCBF") methodology, including the NMV and PAV methodologies, included in PG&E's final 2014 RPS RFO Protocol (Attachment K) has continued to be used as a reference for procurement valuation for mandated programs and as a reference for RPS energy sales. The PAV adjustments in the 2014 protocol represent the value of procurement to PG&E's portfolio. However, the value of additional RPS procurement when PG&E's portfolio is very long or very short may be different than the value of RPS sales under those conditions. Accordingly, as part of this 2018 RPS Plan, PG&E is providing an update to the LCBF methodology approved in its 2014 RPS planning cycle to better reflect current market and portfolio conditions. PG&E's updates to the quantitative LCBF Protocol include: (1) elimination of the energy firmness PAV adder; (2) elimination of the curtailment hours PAV adder; and (3) adjustment of the RPS portfolio position adder to accommodate RPS sales. PG&E is also eliminating the quantitative PAV adjustments for SP15 energy and capacity, and instead adds PG&E's preference for projects located within its service territory as a qualitative adjustment. Finally, PG&E has streamlined the discussion of qualitative factors and eliminated the references to the CPUC Project Viability Calculator. The revised version of PG&E's detailed explanation of its LCBF methodology is included as Appendix H to this 2018 RPS Plan. A redline showing this revised version of the LCBF methodology against the last Commission-approved version (from PG&E's 2014 RPS Plan) is provided for convenience at Appendix I to this 2018 RPS Plan.

PG&E has included in Section 4, above, a description of the framework that PG&E proposes to use to assess whether to hold or sell RPS volumes. The framework itself is included in Confidential Appendix G. The Commission has approved a similar framework in the 2016 and 2017 RPS Plans. As described in Section 4, above, PG&E targets issuing three, with a minimum of two, solicitations in 2019 for short-term (meaning contracts of five years or less in duration) sales of bundled RPS volumes using the framework. PG&E may also seek to negotiate longer-term sales of RPS products after Phase 2 of the PCIA OIR is resolved, depending on the outcome in that proceeding. PG&E has included a solicitation protocol and pro forma sales agreement as Appendix F.3 to this 2018 RPS Plan. The pro forma sales agreement is based on the EEI Master Agreement and is consistent with the form agreement that PG&E used in its 2018 RPS Sales Solicitation. The protocol represents a streamlined approach to selling RPS energy, with the primary selection criterion being price. The protocol and form of sales agreement incorporate lessons learned from the 2018 RPS Sales Solicitation, as described in Sections 4 and 10.

PG&E anticipates that minimal negotiations will be needed with respect to the form sales agreement and proposes filing any executed sales agreements by a Tier 1 Advice Letter for Commission approval. This approach is consistent with the streamlined Tier 1 Advice Letter process authorized in D.14-11-042 for short-term sales agreements. In that decision, the Commission determined that a Tier 1 Advice Letter process could be utilized[53] as long as a utility has included a pro forma short-term contract as part of its approved RPS plan filing and the contract term is under five years. Streamlined processes for both RFO administration and Commission approval are required in order to allow for transactions to occur in 2019.

10.1. Proposed Time of Delivery Factors

PG&E historically set the Time of Delivery ("TOD") factors in its RPS procurement contracts based on expected (internally forecasted) hourly prices, load forecasts, and capacity values. PG&E periodically reviews the effectiveness of these factors, even in RPS planning cycles, like the current one, in which it is not proposing to conduct an RPS solicitation. This is because the TOD factors adopted in the RPS Plan are incorporated into the non-modifiable form contracts used for ongoing mandatory procurement programs and would be used in any future procurement that PG&E either proposes or is directed by the Commission to undertake.

In PG&E's review of the TOD factors for this 2018 RPS Plan, PG&E has determined that it is increasingly difficult to accurately forecast TOD preferences within even the next decade, let alone for the duration of a typical RPS PPA (e.g., 20 years), given California's quickly evolving energy mix, policies, and markets.

PG&E generally supports the efforts of the State to move toward dynamic pricing of both energy demand and energy supply. However, in the absence of having the flexibility to dynamically change the TOD factors in an executed PPA (at least on an annual basis) to adjust to the ongoing changes in the market, TOD factors in a long-term PPA are unlikely to reflect system need over the entire life of the PPA. In fact, changes in the State's net load over time may result in TOD factors incentivizing production under a PPA at times in which the PPA contributes to overgeneration problems, rather than helps to solve them. On the other hand, inserting contractual provisions that allow PG&E to alter TOD factors on a regular basis to match system

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[53] D.14-11-042, pp. 74-78, and implemented in PG&E's approved 2014 RPS Plan.

need could make the PPA difficult or impossible to finance since there would be no certainty around the revenue stream generated by the project.

Given the reasons outlined above, PG&E proposes to eliminate TOD factors for any new RPS procurement contracts that may be executed in the future, including in new contracts to be executed in existing mandatory procurement programs, such as BioMAT. However, pursuant to D.19-02-007, PG&E will calculate TODs for informational purposes only, in order to communicate to developers when energy deliveries might be more valuable to the system and allow developers to respond with optimized project designs and bids.[54] PG&E's proposed informational-only TOD factors will be served on the R.18-07-003 service list within 90 days of issuance of D.19 02-007.[55]

10.2. Workforce Development

SB 2 (1X) added a requirement that the LCBF criteria for ranking and selecting RPS resources shall include "the employment growth associated with the construction and operation of eligible renewable energy resources."[56] The 2018 RPS Plan Ruling directs the IOUs to include a description of a proposed approach for assessing and differentiating the ability of different bids to contribute to employment growth during the construction and operational phases of the project.[57]

PG&E does not expect to procure any RPS resources beyond mandated programs, so there will be limited opportunity to apply a new selection criterion this year. However, PG&E's LCBF methodology does include a qualitative assessment of the extent to which the proposed development supports RPS goals. It is based on information provided by the Seller and PG&E's assessment of that information. If PG&E were procuring RPS resources, it would require bidders to submit information on

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54 D.19-02-007, OP 16.

55 *Id.,* OP 17.

56 Cal. Pub. Util. Code § 393.13(a)(4)(A)(iv).

57 2018 RPS Plan Ruling, p. 14.

projected California employment growth during construction and operation. This would include number of hires, duration of hire, and indication of whether the bidder has entered into Project Labor Agreements or Maintenance Labor Agreements in California for the proposed project. This information was required from bidders in PG&E's 2014 RPS RFO.[58]

10.3. Disadvantaged Communities

SB 2 (1X) also added the requirement that preference shall be given "to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases."[59] The 2018 RPS Plan Ruling directs the IOUs to include a description of their methodology for preferring projects that provide those benefits.[60]

As explained above, PG&E does not expect to procure any RPS resources beyond mandated programs, so there will be limited opportunity to apply a new selection criterion this year. However, PG&E has included this component as part of its assessment of an offer's consistency with and contribution to California's goal for the RPS Program. PG&E's LCBF methodology includes a qualitative assessment of the extent to which the proposed development supports RPS goals is based on information provided by the Seller, and PG&E's assessment of that information.

If PG&E were procuring resources, it would expect to solicit information from participants similar to what was required in the 2014 RPS RFO.[61] PG&E asked participants to respond to the following questions on this topic:

> Is your facility located in a community afflicted with poverty or high unemployment or that suffers from high emission levels? If so, the Participant is encouraged to describe in its Offer, if applicable, how its proposed facility can provide the following benefits to adjacent communities:

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58 Appendix J2 to 2014 RPS RFO Protocol.

59 Cal. Pub. Util. Code § 399.13(a)(7).

60 2018 RPS Plan Ruling, p. 15.

61 Appendix J2 to 2014 RPS RFO Protocol.

- Projected hires from adjacent community (number and type of jobs),
- Duration of work (during construction and operation phases),
- Projected direct and indirect economic benefits to the local economy (i.e., payroll, taxes, services),
- Emissions reduction – Identify existing generation sources by fuel source within 6 miles of proposed facility; Will the proposed facility replace/supplant identified generation sources?
  - If “yes”, provide estimated reduction in air pollutants/toxics in the community over life of the project/contract due to the facility (when/how much MWh/year), and avoided emissions released into the community (within 6 miles of the project).
  - If “No”, why not?

10.4. 2018 RPS Sales – Lessons Learned

While PG&E has executed a limited number of agreements for the sale of RPS volumes from PG&E’s portfolio, PG&E’s second such solicitation (the “2018 RPS Sales Solicitation”) was issued in 2018. Upon completion of the 2018 RPS Sales Solicitation, PG&E surveyed market participants to solicit feedback on how to improve the process and to understand why certain market participants did not bid. In addition, PG&E received feedback from the Independent Evaluator assigned to monitor the solicitation and resulting negotiations.

As a result, PG&E has identified a number of best practices to incorporate for future solicitations. They include:

Desire for PCC Certainty

Counterparties consistently sought contract language certifying that the bundled RPS volumes to be sold and purchased would be deemed to be PCC 1 by the CPUC. PG&E agreed to represent that the resources used for the sale, if retired for compliance by PG&E, would be expected to meet the definition of PCC 1 as described in Pub. Util. Code Section 399.16(b)(1). However, PG&E was unable to provide the certification that buyers requested because any such determination is outside of PG&E’s control. The CPUC determines the applicable PCC category of RPS products used by retail sellers to meet RPS compliance requirements in a process that is independent from, and later in time from, the process to review and approve a contract executed by PG&E for the sale of RPS volumes. Given the request presented to PG&E, PG&E believes that it would facilitate the sale of bundled RPS volumes if the CPUC determined the PCC of the products as to the purchasing entity in connection with the Advice Letter approval process to review the sales agreement.

Product Term

In 2018, PG&E sought sales with energy deliveries in multiple years (2018 through 2022) rather than in a single year as it had previously solicited in 2017. Buyers were receptive to the extended term of energy deliveries in the 2018 RPS Sales Solicitation and conveyed their preference sales for multiple years rather than single years. In 2019, PG&E will continue to solicit sales with deliveries across multiple years.

Timing and Timeline of Solicitation

[redacted]

To address these concerns PG&E will conduct future solicitations in a very streamlined manner, and as described in Section 4, above, intends to target issuing three, with a minimum of two, solicitations during calendar year 2019. PG&E aims to issue its first 2019 RPS Sales Solicitation shortly after the 2018 RPS Plan has received final approval from the CPUC.

Execution Process

In future Sales Solicitations, PG&E will identify in advance which areas of the sales agreement are eligible to be discussed. Using the standardized form of agreement developed in 2017, PG&E engaged in limited discussions with buyers in 2018. [redacted] As a result, PG&E expects discussions with buyers on the sales agreement to be minimal in 2019 to streamline the execution process.

11. **Consideration of Price Adjustment Mechanisms**

The 2018 RPS Plan Ruling requires each IOU to "describe how price adjustments (e.g., index to key components, index to Consumer Price Index ("CPI"), price adjustments based on exceeding transmission or other cost caps, etc.) will be considered and potentially incorporated into contracts for RPS-eligible projects with online dates occurring more than 24 months after the contract execution date."[62]

In this 2018 RPS Plan, PG&E is proposing to not hold an RPS solicitation in 2018. If PG&E was negotiating PPAs for additional procurement, PG&E might consider a non-standard PPA with pricing terms that are indexed, but indexed pricing should be the exception rather than the rule. Customers could benefit from pricing indexed to the cost of key components, such as solar panels or wind turbines, if those prices decrease in the future. Conversely, customers would also face the risk that they will pay more for the energy should prices of those components increase. Asking customers to accept this pricing risk reduces the rate stability that the legislature has found is a benefit of the RPS Program.[63] In order to maximize the RPS Program's benefits to customers, cost risk should generally be borne by developers.

Additionally, indexing greatly complicates offer selection, negotiation and approval. It may be challenging to incorporate contract price adjustment mechanisms into PPA negotiations when there is no clear, well-established and well-defined agreed-upon index. There are many components to the cost of construction of a renewable project, and indexes tied to these various components may move in different directions. The increased complexity inherent in such negotiations is counter to the

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62 2018 RPS Plan Ruling, p. 15.

63 Cal. Pub. Util. Code § 399.11(b)(5).

Commission's expressed desire to standardize and simplify RPS solicitation processes.[64]

Moreover, Sellers may not have as much incentive to reduce costs if certain cost components are indexed. For example, a price adjustment based on the cost of solar panels (i.e., if panel costs are higher than expected, the price may adjust upward) may not create enough incentive to minimize those costs. This would create a further level of complexity in contract administration and regulatory oversight.

Finally, PG&E does not recommend that PPA prices be linked to the CPI. The CPI is completely unrelated to the cost of the renewable resource, and is instead linked to increases in prices of oil and natural gas, food, medical care and housing. Indexing prices to unrelated commodities heightens the derivative and speculative character of these types of transactions.

12. **Economic Curtailment**

In D.14-11-042, the Commission directed that the IOUs describe in future RPS Plans how "expected economic curtailment affects their RPS procurement."[65] In addition, the Commission directed the IOUs to report on observations and issues related to economic curtailment, including reporting to the PRG.[66] In July 2018, PG&E made a presentation to its PRG on economic curtailment. This section provides information to the Commission and parties regarding PG&E's observations and issues related to economic curtailment both for the market generally, and PG&E's specific scheduling practices for its RPS-eligible resources.

With regard to market conditions generally, the frequency of negative price periods in the first part of 2018 has decreased in the Real-Time Markets ("RTM") for the PG&E Default Load Aggregation Point (DLAP) and for the North of Path 15 Hub ("NP15 Hub") as compared to previous years. During January through April 2018, negative

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64 D.11-04-030, pp. 33-34.

65 D.14-11-042, p. 45.

66 *Id*., pp. 42-43.

price intervals in the CAISO Five Minute Market for the PG&E DLAP occurred in approximately 4.2 percent of the 5-minute intervals, compared to approximately 13.5 percent during the same period in 2017 and 7.6 percent during the same period in 2016. Trends are similar for NP 15 and ZP 26. The specific occurrences of negative price periods and overgeneration events are largely unpredictable; [redacted] to minimize exposure to negative pricing.

[redacted]

[redacted][67] [redacted] PG&E submits bids for these resources based on the resource's opportunity costs, subject to contractual, regulatory, and operational constraints. [redacted] PG&E provided more detail concerning its RPS bidding strategy in its Bundled Procurement Plan[68] which was approved by the Commission in D.15-10-031.

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67 [redacted]

68 See PG&E, 2014 Bundled Procurement Plan, Appendix K (Bidding and Scheduling Protocol).

[redacted][69] [redacted][70] While direct benefits of economic bidding include avoided costs and CAISO market payments associated with negative prices, there can be other important benefits, including potentially avoiding the cost impacts across the rest of PG&E's portfolio due to extreme negative price periods, and also CAISO system reliability by helping to mitigate the occurrences, duration, or severity of negative price periods or overgeneration events. The overall trends in both the frequency and magnitude of negative prices in recent years suggests that the CAISO is able to generally balance supply and demand using economic curtailment rather than administratively curtailing generation.

Regarding longer-term RPS planning and compliance, in order to ensure that RPS procurement need forecasts account for curtailment, PG&E adds curtailment as a risk adjustment within the stochastic model. For a discussion of forecasted curtailment levels please see Section 7.2.3. PG&E will continue to observe curtailment events and update its curtailment assumptions as needed.

Finally, PG&E continues to review its existing portfolio of RPS contracts to determine if additional economic curtailment flexibility may be available to help address the increase in oversupply events.

13. Cost Quantification

This section summarizes results from actual and forecasted RPS generation costs (including incremental rate impacts), shows potential increased costs from

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69 Net load refers to normal demand for electricity minus the contribution from solar and wind generation.

70 [redacted]

mandated programs, and identifies the need for a clear cost containment mechanism to address RPS Program costs. Tables 1 through 4 in Appendix B provide an annual summary of PG&E's actual and forecasted RPS costs and Page 1 of Appendix B outlines the methodology for calculating the costs and generation.

13.1. RPS Cost Impacts

Appendix B quantifies the cost of RPS-eligible procurement—both historical (2003-2017) and forecast (2018-2030). From 2003 to 2017, PG&E's annual RPS-eligible procurement and generation costs have continued to increase. Compared to an annual cost of $523 million in 2003, PG&E incurred more than $2.4 billion in procurement costs for RPS-eligible resources in 2017.

RPS Program costs impact customers' bills. Incremental rate impacts, defined as the annual total cost from RPS-eligible procurement and generation divided by bundled retail sales, effectively serve as an estimate of a system average bundled rate for RPS-eligible procurement and generation.[71] While this formula does not provide an estimate of the renewable "above-market premium" that customers pay relative to a non-RPS-eligible power alternative, the annual rate impact results in Tables 1 and 2 of Appendix B illustrate the potential rate of growth in RPS costs and the impact this growth will have on average rates, all other factors being equal. Annual rate impact of the RPS Program increased from 0.7¢/kWh in 2003 to an estimated 4.8¢/kWh in 2018, meaning the average rate impact from RPS-eligible procurement has increased by nearly seven-fold in approximately 15 years. As load departure increased and accelerated in recent years, flaws in the PCIA methodology have caused bundled customers to bear a disproportionately high share of this rate impact. This growth rate is projected to continue increasing through 2021, as the average rate impact is forecasted to increase to 6.8¢/kWh. In addition to the increasing RPS costs and incremental rate impacts on customer costs resulting from the direct procurement of the

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71 These rates do not reflect allocated costs to departed load (e.g., DA and Community Choice Aggregation customers). Without taking into account the allocation credit the illustrative rate impacts are higher than the forecasted bundled rate impact.

renewable resources, there are incremental indirect transmission and integration costs associated with that procurement.

13.2. Cost Impacts Due to Mandated Programs

The cost impacts of mandated procurement programs that focus on particular technologies or project size have comprised an increasing share of PG&E's incremental procurement in recent years, to the extent that incremental procurement is now entirely mandated by Commission programs.

In general, mandated procurement programs do not optimize RPS costs for customers because they restrict flexibility and optionality to achieve emissions reductions by mandating procurement through a less efficient and more costly manner. For instance, research shows that market-based mechanisms, like cap-and-trade, that allow multiple and flexible emissions reduction options, have lower costs than mandatory mechanisms like technology targets that allow only a subset of those options.[72] Studies have also shown that renewable electricity mandates increase prices and costs,[73] and procurement mandates within California's RPS decrease efficiency in the same way.

Mandates restrict the choices to meet the RPS targets, removing potentially less expensive options from the market. This can increase prices in two ways: first, by disqualifying those less expensive participants; and second, by creating a less robust

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72 *See*, *e.g.*, Palmer and Burtraw, "Cost-Effectiveness of Renewable Electricity Policies" (2005) (available at http://www.rff.org/Documents/RFF-DP-05-01.pdf); Sergey Paltsev et al., "The Cost of Climate Policy in the U.S." (2009) (available at http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.177.6721&rep=rep1&type=pdf); Palmer, Sweeney, and Allaire, "Modeling Policies to Promote Renewable and Low-Carbon Sources of Electricity" (2010) (available at http://www.rff.org/files/sharepoint/WorkImages/Download/RFF-BCK-Palmeretal%20-LowCarbonElectricity-REV.pdf).

73 *See*, *e.g.*, Institute for Energy Research, "Energy Regulation in the States: A Wake-up Call"; Manhattan Institute, "The High Cost of Renewable Electricity Mandates" (available at http://www.manhattan-institute.org/html/eper_10.htm).

market for participants to compete.[74] PG&E's customers also pay incremental costs due to the administrative costs associated with managing separate solicitations for mandated resources. In addition, smaller project sizes for mandated programs create a greater number of projects which, in turn, affect interconnection and transmission availability and costs. Finally, mandated programs do not enable PG&E to procure the technology, size, vintage, location and other attributes that would best fit its portfolio. As a result, PG&E's costs for managing its total generation and portfolio increase. For these reasons, PG&E supports a technology neutral procurement process, in which all technologies can compete to demonstrate which projects provide the best value to customers at the lowest cost.

14. Important Changes to Plans Noted

This Section describes the most significant changes between PG&E's Final 2017 RPS Plan and its Draft 2018 RPS Plan as filed on August 20, 2018. A complete redline of the Draft 2018 RPS Plan against PG&E's Final 2017 RPS Plan is included as Appendix I of the Draft 2018 RPS Plan originally filed on August 20, 2018. The table below provides a list of key differences between the two RPS Plans:

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74 *See*, Fischer and Preonas, "Combining Policies for Renewable Energy: Is the Whole Less Than the Sum of Its Parts?" (2010) (available at http://www.rff.org/Documents/Fischer_Preonas_IRERE_2010.pdf).

TABLE 14-1
SUMMARY OF CHANGES

Reference	Area of Change	Summary of Change
Draft Plan Document and Appendices	Expiring Contracts, Imperial Valley, Project Development Status Update, Expiring Contracts	Removed Sections
Section 10.1	Proposed TOD Factors	Eliminated for any new RPS contracts
Section 10.4	2018 RPS Sales - Lessons Learned	Updated based on 2018 RPS Sales lessons learned
Section 4 and Appendix G	Sales Framework	Updated based on 2017 RPS Plan lessons learned
Appendix H	Least-Cost, Best-Fit Methodology	Updates to reflect current market conditions

15. Safety Considerations

PG&E is committed to providing safe utility (electric and gas) service to its customers. As part of this commitment, PG&E reviews its operations, including energy procurement, to identify and mitigate, to the extent possible, potential safety risks to the public and PG&E's workforce and its contractors. Because PG&E's role in ensuring the safe construction and operation of RPS-eligible generation facilities depends upon whether PG&E is the owner of the generation or is simply the contractual purchaser of RPS-eligible products (e.g., energy and RECs), this section is divided into separate discussions addressing each of these situations.

15.1. Development and Operation of PG&E-Owned, RPS-Eligible Generation

While PG&E is not proposing as part of its 2018 RPS Plan to develop additional utility-owned renewable facilities, its existing RPS portfolio contains a number of such facilities. To the extent that PG&E builds, operates, maintains, and decommissions its own RPS-eligible generation facilities, PG&E follows its internal standard protocols and practices to ensure public, workplace, and contractor safety. For example, PG&E's Employee Code of Conduct sets the standard that PG&E employees will put safety first.[75] PG&E's commitment to a safety-first culture is reinforced by a speak-up culture.[76] These tools were developed in collaboration with PG&E employees, leaders, and union leadership and are intended to provide clarity and support as employees strive to take personal ownership of safety at PG&E. Additionally, PG&E seeks all applicable regulatory approvals from governmental authorities with jurisdiction to enforce laws related to worker health and safety, impacts to the environment, and public health and welfare.

As more fully detailed in PG&E's testimony in its last General Rate Case ("GRC"),[77] the top priority of PG&E's Electric Supply organization is public and employee safety, and its goal is to safely operate and maintain its generation facilities. In general, PG&E ensures safety in the development and operation of its RPS-eligible facilities in the same manner as it does for its other UOG facilities. This includes the use of recognized best practices in the industry.

PG&E operates each of its generation facilities in compliance with all local, state and federal permit and operating requirements such as state and federal Occupational Safety and Health Administration ("OSHA") and the CPUC's General Order 167. PG&E does this by using internal controls to help manage the operations and maintenance of its generation facilities, including: (1) guidance documents; (2) operations reviews; (3) an incident reporting process; (4) a corrective action program; (5) an outage planning and scheduling process; (6) a project management process; and (7) a design change process.

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75 *See* PG&E, "Employee Code of Conduct" (February 2018) (available at http://www.pgecorp.com/aboutus/corp_gov/coce/employee_conduct_standards.shtml). *See*, *e.g.*, PG&E, "Contractor, Consultant, and Supplier Code of Conduct," p. 4 (available at https://www.pge.com/includes/docs/pdfs/b2b/purchasing/suppliers/SupplierCodeofConductPGE.pdf).

76 *See* PG&E, "Employee Code of Conduct" *supra*, p. 21 *et seq.*

77 *See* PG&E, *Prepared Testimony, 2017 GRC, Application 15-09-001*, Exhibit (PG&E-5), Energy Supply, pp. 1-18 to 1-19 (available at https://www.pge.com/en_US/about-pge/company-information/regulation/regulation.page).

PG&E's Environmental Services organization also provides direct support to the generation facilities, with a focus on regulatory compliance. Environmental consultants are assigned to each of the generating facilities and support the facility staff.

Regarding employee safety, Power Generation employees develop a safety action plan each year. This action plan focuses on various items such as clearance processes and electrical safety, switching and grounding observations, training and qualifications, expanding the use of Job Safety Analysis tools, peer-to-peer recognition, near-hit reporting, industrial ergonomics, and human performance. Employees also participate in activities developed and conducted by an employee-led Driver Awareness Team established for the sole purpose of improving driving.

The day-to-day safety work in the operation of PG&E's generation facilities consists of base activities such as:

- Industrial and office ergonomics training/evaluations
- Illness and injury prevention
- Health and wellness training
- Regulatory mandated training
- Contractor Safety Oversight Program,
- Training and recertification for the safety staff
- Culture based safety process
- Asbestos and lead awareness training
- Safety at Heights Program
- Safe driving training
- First responder training
- Preparation of safety tailboards and department safety procedures
- Proper use of personal protective equipment
- Incident investigations and communicating lessons learned
- Near Hit (close call) reporting
- Employee injury case management
- Safety performance recognition
- Public safety awareness
- Corrective Actions Program

The safety focus of PG&E's hydropower operations includes the safety of the public at, around, and/or downstream of PG&E's facilities; the safety of our personnel at and/or traveling to PG&E's hydro facilities; and the protection of personal property potentially affected by PG&E's actions or operations. Regarding public safety, PG&E has developed and implemented a comprehensive public safety program that includes: (1) public education, outreach and partnership with key agencies; (2) improved warning and hazard signage at hydro facilities; (3) enhanced emergency response preparedness, training, drills and coordination with emergency response organizations; and (4) safer access to hydro facilities and lands, including trail access, physical barriers, and canal escape routes.

PG&E has also funded specific hydro-related projects that correct potential public and employee safety hazards, such as Arc Flash Hazards, inadequate ground grids, and waterway, penstock, and other facility safety condition improvements.

Over the past several years, PG&E's Power Generation organization has been creating a culture of safety first with strong leadership expectations and an increasingly engaged workforce. Fundamental to a strong safety culture is a leadership team that believes every job can be performed safely and seeks to eliminate barriers to safe operations. Equally important is the establishment of an empowered grass roots safety team that acts to encourage safe work practices among peers. Power Generation's grass roots team is led by bargaining unit employees from across the organization who work to include safety best practices in all the work they do. These employees are closest to the day-to-day work of providing safe, reliable, and affordable energy for PG&E's customers and are best positioned to implement changes that can improve safety performance.

15.2. Development and Operation of Third-Party–Owned, RPS-Eligible Generation

The vast majority of PG&E's procurement of products to meet RPS requirements has been from third-party generation developers. In these cases, local, state and federal agencies that have review and approval authority over the generation facilities are charged with enforcing safety, environmental and other regulations for the Project, including decommissioning. PG&E's contract provisions reinforce the developer's obligations to safety by requiring them to operate in accordance with all applicable safety laws, rules and regulations as well as Prudent Electrical Practices, which are the continuously evolving industry standards for operations of similar electric generation facilities.

PG&E's recent contract provisions seek to instill a continuous improvement safety culture that mirrors PG&E's "Contractor Safety Standard" pursuant to D.15-07-014. These provisions require developers to demonstrate their use of safeguards, equipment and personnel training, and require reporting of Serious Incidents and Exigent Circumstances shortly after they occur. Such provisions were included in the executed agreements arising out of the 2014 and 2016 Energy Storage Requests for Offers ("RFOs") and could be incorporated in future RPS form PPAs if PG&E's RPS position resulted in a need for RPS procurement.

During the development process, PG&E receives monthly progress reports from generators who are developing new RPS-eligible resources where the output will be sold to PG&E. As part of this progress report, generators are required to provide the status of construction activities, including safety updates such as OSHA recordables and work stoppage information.

Safety is also addressed as part of a generator's interconnection process, which requires testing for safety and reliability of the interconnected generation. PG&E's general practice is to declare that a facility under contract has commenced deliveries under the PPA only after the interconnecting utility and the CAISO have concluded such testing and given permission to commence commercial operations.

The decommissioning of a third-party generation project is not addressed in the form contract. In many cases, it may be expected that a third-party generator may continue to operate its generation facility after the PPA has expired or terminated, perhaps with another off-taker. Any requirements and conditions for decommissioning of a generation facility owned by a third-party should be governed by the applicable permitting authorities.

16. **Energy Storage**

AB 2514, signed into law in September 2010, added Section 2837, which requires that the IOUs' RPS procurement plans incorporate any energy storage targets and policies that are adopted by the Commission as a result of its implementation of AB 2514. On October 17, 2013, the CPUC issued D.13-10-040 adopting an energy storage procurement framework and program design, requiring that PG&E execute 580 MW of storage capacity by 2020, with projects required to be installed and operational by no later than the end of 2024. In accordance with the guidelines in the decision, PG&E completed its 2014 and 2016 Energy Storage RFOs. On December 1, 2017, PG&E submitted six executed agreements that resulted from the 2016 Energy Storage RFO for CPUC approval.[78]

In January 2018, the CPUC authorized PG&E to launch an accelerated solicitation for energy storage projects to contribute to reliability needs for three specified local subareas in the northern central valley and in an area spanning Silicon Valley to the central coast (Pease, Bogue, and South Bay – Moss Landing local sub-areas). PG&E issued its RFO in February 2018 and received offers from numerous participants. After careful evaluation, PG&E selected and submitted for approval four projects to be located within the South Bay – Moss Landing local sub-area: one offer for a 182.5 MW utility-owned project and three offers for 385 MW of third-party owned projects, which include a 10 MW aggregation of customer-sited storage.[79] Energy storage procured to meet the local sub area need will be used to meet PG&E's AB 2514

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78 A.17-12-003. Application of Pacific Gas and Electric Company (U 39-E) for Approval of Agreements Resulting from Its 2016-2017 Energy Storage Solicitation and Related Cost Recovery.

79 Advice 5322-E, Energy Storage Contracts Resulting from PG&E's Local sub-area Request for Offers Per Res. E-4909, submitted June 29, 2018.

targets. These projects are also expected to help increase the overall flexibility of the grid to integrate high levels of wind and solar generation.

AB 2868, signed into law in September 2016, added Sections 2838.2 and 2838.3, which requires that the IOUs file applications for programs and investments to accelerate widespread deployment of distributed energy storage systems. In March 2018, PG&E filed its proposal with the CPUC to deploy 166.66 MW of distributed energy storage in compliance with AB 2868.[80]

PG&E would consider meeting its Energy Storage Program targets through eligible energy storage systems procured through its RPS process (to the extent that PG&E seeks authorization to solicit incremental RPS procurement in the future) and its Energy Storage RFOs, as well as other CPUC programs and channels such as the Self-Generation Incentive Program. PG&E's LCBF methodology considers the additional value offered by RPS-eligible generation facilities that incorporate energy storage. Further detail on PG&E's energy storage procurement can be found in its biennial Energy Storage Plan.[81]

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80 A.18-03-001, Application of PG&E for Approval of its 2018 Energy Storage Procurement and Investment Plan, filed March 1, 2018.

81 *See ibid.*

APPENDIX A.1

Renewable Net Short Calculations

March 15, 2019

Table 1: Renewable Net Short Calculation as of June 2018[13, 14]

Net Short Calculation Using PG&E Bundled Retail Sales Forecast In Near Term (2018 - 2022) and LTPP Methodology (2023 - 2036)

Variable	Calculation in Energy Division RNS Calculation Template	Revised Calculation Correcting Apparent Errors in Energy Division Template	Item	Deficit from RPS prior to Reporting Year	2011 Actuals	2012 Actuals	2013 Actuals	**2011-2013**	2014 Actuals	2015 Actuals	2016 Actuals	**2014-2016**	2017 Actuals	2018 Forecast	2019 Forecast	2020 Forecast	**2017-2020**	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	**2021 - 2024**
			Forecast Year		-	-	-	CP1	-	-	-	CP2	-	-	-	-	CP3	-	-	-	-	CP4
			Annual RPS Requirement																			
A			Bundled Retail Sales Forecast (LTPP)[1]		74,864	76,205	75,705	226,774	74,547	72,113	68,441	215,101	61,397	[redacted]	37,069	[redacted]	[redacted]	[redacted]	33,826	35,964	35,687	[redacted]
B			RPS Procurement Quantity Requirement (%)		20.0%	20.0%	20.0%	20.0%	21.7%	23.3%	25.0%	23.3%	27.0%	29.0%	31.0%	33.0%	30.0%	35.8%	38.5%	41.3%	44.0%	39.9%
C	A*B		**Gross RPS Procurement Quantity Requirement (GWh)**		14,973	15,241	15,141	45,355	16,177	16,802	17,110	50,089	16,577	[redacted]	11,491	[redacted]	[redacted]	[redacted]	13,023	14,835	15,702	[redacted]
D			Voluntary Margin of Over-procurement[2]		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E	C+D		**Net RPS Procurement Need (GWh)**		14,973	15,241	15,141	45,355	16,177	16,802	17,110	50,089	16,577	[redacted]	11,491	[redacted]	[redacted]	[redacted]	13,023	14,835	15,702	[redacted]
			RPS-Eligible Procurement																			
Fa			Risk-Adjusted RECs from Online Generation[3]		14,699	14,513	17,212	46,424	20,207	21,285	22,551	64,042	22,345	20,520	20,700	20,428	83,993	20,076	17,608	16,856	16,578	71,118
Faa			Forecast Failure Rate for Online Generation (%)		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fb			Risk-Adjusted RECs from RPS Facilities in Development[4]		-	-	-	-	-	-	0	-	-	26	588	769	1,384	985	981	977	974	3,916
Fbb			Forecast Failure Rate for RPS Facilities in Development (%)		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fc			Pre-Approved Generic RECs		-	-	-	-	-	-	-	-	-	-	0	91	92	360	631	764	862	2,616
Fd			Executed REC Sales		-	-	(142)	(142)	(50)	-	(60)	(110)	(2,069)	(1,376)	(4,729)	(1,853)	(10,027)	(300)	-	-	-	(300)
F	Fa + Fb +Fc - Fd	Fa + Fb +Fc + Fd	Total RPS Eligible Procurement (GWh)[5]		14,699	14,513	17,069	46,281	20,157	21,285	22,491	63,932	20,276	19,170	16,559	19,436	75,442	21,120	19,220	18,597	18,414	77,351
F0			Category 0 RECs		14,651	13,049	14,163	41,863	16,899	17,408	17,914	52,222	14,804	13,873	10,985	12,447	52,109	13,284	11,199	10,903	10,675	46,060
F1			Category 1 RECs		48	1,464	2,906	4,418	3,257	3,876	4,577	11,710	5,471	5,873	6,724	6,990	25,058	7,837	8,022	7,694	7,738	31,291
F2			Category 2 RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F3			Category 3 RECs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
			Gross RPS Position (Physical Net Short)																			
Ga	F-E		**Annual Gross RPS Position (GWh)**		(274)	(728)	1,928	926	3,980	4,482	5,381	13,843	3,699	[redacted]	5,068	[redacted]	[redacted]	[redacted]	6,197	3,761	2,711	[redacted]
Gb	F/A		**Annual Gross RPS Position (%)**		19.6%	19.0%	22.5%	20.4%	27.0%	29.5%	32.9%	29.7%	33.0%	[redacted]	44.7%	[redacted]	[redacted]	[redacted]	56.8%	51.7%	51.6%	[redacted]
			Application of Bank																			
Ha	H - Hc (from previous year)	J - Hc (from previous year)	Existing Banked RECs above the PQR[6,7]		-	(274)	(1,033)	-	861	4,815	9,274	861	14,630	18,200	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hb			RECs above the PQR added to Bank		(274)	(728)	1,928	926	3,980	4,482	5,381	13,843	3,699	[redacted]	5,068	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hc			Non-bankable RECs above the PQR[8]		-	31	34	65	26	23	25	74	129	2	-	-	132	-	-	-	-	-
H	Ha+Hb		Gross Balance of RECs above the PQR		(274)	(1,002)	895	926	4,841	9,297	14,655	14,704	18,329	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ia			Planned Application of RECs above the PQR towards RPS Compliance		-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ib			Planned Sales of RECs above the PQR[9]		-	-	-	-	-	-	-	-	-	(693)	-	(216)	(909)	(1,769)	(2,069)	(2,069)	(2,069)	(7,976)
J	H-Ia-Ib	H-Ia+Ib	Net Balance of RECs above the PQR[6]		(274)	(1,002)	895	926	4,841	9,297	14,655	14,704	18,329	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
J0			Category 0 RECs		-	-	-	-	657	1,237	2,019	2,067	2,067	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
J1			Category 1 RECs		-	-	895	926	4,184	8,060	12,636	12,636	16,261	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
J2			Category 2 RECs		-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
			Expiring Contracts																			
K			RECs from Expiring RPS Contracts[10]		N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	-	98	444	710	1,253	966	3,380	4,080	4,357	12,784
			Net RPS Position (Optimized Net Short)																			
La	Ga + Ia – Ib – Hc	Ga + Ia + Ib	**Annual Net RPS Position after Bank Optimization (GWh)** [11]		(274)	(728)	1,928	926	3,980	4,482	5,381	13,843	3,699	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lb	(F + Ia – Ib – Hc)/A	(C + La) / A	**Annual Net RPS Position after Bank Optimization (%)** [11, 12]		19.6%	19.0%	22.5%	20.4%	27.0%	29.5%	32.9%	29.7%	33.0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Variable	Item	2025 Forecast	2026 Forecast	2027 Forecast	**2025 - 2027**	2028 Forecast	2029 Forecast	2030 Forecast	**2028 - 2030**	2031 Forecast	2032 Forecast	2033 Forecast	**2031 - 2033**	2034 Forecast	2035 Forecast	2036 Forecast	**2034- 2036**
	Forecast Year	-	-	-	CP5	-	-	-	CP6	-	-	-	CP7	-	-	-	CP8
	Annual RPS Requirement																
A	Bundled Retail Sales Forecast (LTPP)[1]	35,602	35,355	35,115	106,072	34,792	34,505	34,187	103,485	34,102	34,016	33,931	102,049	33,847	33,762	33,677	101,286
B	RPS Procurement Quantity Requirement (%)	46.7%	49.3%	52.0%	49.3%	54.7%	57.3%	60.0%	57.3%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%
C	**Gross RPS Procurement Quantity Requirement (GWh)**	16,614	17,442	18,260	52,316	19,020	19,783	20,512	59,315	20,461	20,410	20,359	61,230	20,308	20,257	20,206	60,772
D	Voluntary Margin of Over-procurement[2]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E	**Net RPS Procurement Need (GWh)**	16,614	17,442	18,260	52,316	19,020	19,783	20,512	59,315	20,461	20,410	20,359	61,230	20,308	20,257	20,206	60,772
	RPS-Eligible Procurement																
Fa	Risk-Adjusted RECs from Online Generation[3]	16,417	15,883	15,627	47,927	15,570	14,999	14,928	45,497	14,164	13,620	12,384	40,168	11,120	10,013	9,333	30,467
Faa	Forecast Failure Rate for Online Generation (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fb	Risk-Adjusted RECs from RPS Facilities in Development[4]	968	963	959	2,889	956	950	945	2,851	941	939	932	2,811	563	501	384	1,447
Fbb	Forecast Failure Rate for RPS Facilities in Development (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fc	Pre-Approved Generic RECs	957	1,037	1,102	3,095	1,108	1,104	1,103	3,316	1,102	1,103	1,099	3,304	1,098	1,097	1,098	3,293
Fd	Executed REC Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F	Total RPS Eligible Procurement (GWh)[5]	18,341	17,883	17,687	53,911	17,635	17,053	16,976	51,664	16,207	15,662	14,415	46,284	12,781	11,611	10,815	35,207
F0	Category 0 RECs	10,556	10,046	9,816	30,418	9,768	9,240	9,195	28,204	8,524	8,420	7,789	24,733	7,158	6,711	6,701	20,569
F1	Category 1 RECs	7,785	7,837	7,871	23,494	7,866	7,812	7,781	23,460	7,683	7,242	6,625	21,551	5,623	4,900	4,114	14,637
F2	Category 2 RECs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F3	Category 3 RECs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Gross RPS Position (Physical Net Short)																
Ga	**Annual Gross RPS Position (GWh)**	1,726	441	(572)	1,596	(1,385)	(2,730)	(3,536)	(7,651)	(4,254)	(4,748)	(5,944)	(14,946)	(7,527)	(8,646)	(9,391)	(25,565)
Gb	**Annual Gross RPS Position (%)**	51.5%	50.6%	50.4%	50.8%	50.7%	49.4%	49.7%	49.9%	47.5%	46.0%	42.5%	45.4%	37.8%	34.4%	32.1%	34.8%
	Application of Bank																
Ha	Existing Banked RECs above the PQR[6,7]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hb	RECs above the PQR added to Bank	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hc	Non-bankable RECs above the PQR[8]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H	Gross Balance of RECs above the PQR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ia	Planned Application of RECs above the PQR towards RPS Compliance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ib	Planned Sales of RECs above the PQR[9]	(2,069)	(2,069)	(2,069)	(6,207)	(2,069)	(2,069)	(2,069)	(6,207)	(2,069)	(2,069)	(2,069)	(6,207)	-	-	-	-
J	Net Balance of RECs above the PQR[6]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
J0	Category 0 RECs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
J1	Category 1 RECs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
J2	Category 2 RECs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Expiring Contracts																
K	RECs from Expiring RPS Contracts[10]	4,420	4,901	5,112	14,434	5,164	5,642	5,667	16,474	5,992	6,535	7,680	20,207	9,272	10,335	11,317	30,924
	Net RPS Position (Optimized Net Short)																
La	**Annual Net RPS Position after Bank Optimization (GWh)** [11]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lb	**Annual Net RPS Position after Bank Optimization (%)** [11, 12]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

General Table Notes: Values are shown in GWhs. Fields in grey are protected as Confidential under CPUC Confidentiality Rules.

(1) (Row A) Forecasts of retail sales through 2022 are reflective of PG&E's internal bundled retail sales forecast less interdepartmental (metered usage at PG&E-owned facilities) and GTSR sales.

Forecasts post-2022 use the 2017-2018 IRP Cycle forecast (successor to LTPP proceeding planning process).

(2) (Row D) As a portion of the Bank will be used as VMOP, Row D will remain zero. See Draft 2018 RPS Plan for a description of PG&E's VMOP.

(3) (Row Fa) "Online Generation" includes forecasted volumes from replacement contracts (i.e. ReMAT contracts replacing QF contracts) for facilities that are already online.

(4) (Row Fb) "In Development" includes forecasted volumes from phase-in projects. This is consistent with labeling in the RPS Database (which labels phase-in projects as "In Development" under "Overall Project Status").

(5) (Row F) Row F has subtracted 134 GWh of RECs associated with 2011 generation from the Hay Canyon Wind Facility and the Nine Canyon Wind Phase 3. These RECs are not being used for RPS compliance because they were not retired within the RPS statute's 36-month REC retirement deadline.

(6) (Rows Ha and J) As PG&E's Alternative RNS incorporates additional risk-adjustments to the results from the Physical Net Short, the Bank sizes indicated in Rows Ha and J may differ from Rows Ha and J of the Alternative RNS, which shows the stochastically-adjusted Bank size.

(7) (Rows Ha) At the beginning of each compliance period Row Ha subtracts previous compliance non-bankable volumes from the previous compliance period net balance of RECs. For example, the 2021 forecast for Row Ha is equivalent to the Row J in CP3 minus Row Hc in CP3.

(8) (Row Hc) Since PG&E elected to comply early in the 2017-2020 period with the banking rules established in D.17-06-026, PG&E has modeled the new banking rules for the current and future compliance periods.

(9) (Row Ib) The annual RPS sales volume forecast assumption is based on actual RPS sales completed in 2017 and is included for RPS position planning purposes. Row Ib is reduced by executed REC sales volumes included on Row Fd.

(10) (Row K) Row K now includes only expiring volumes from contracts as of June 2018.

(11) (Rows La and Lb) Rows La and Lb incorrectly subtract the non-bankable volumes. Although these volumes can not be carried forward, per Decision 12-06-038, these volumes could be used towards meeting compliance in the current period. Therefore, the non-bankable volumes should be included in the Annual Net RPS Position after Bank Optimization.

(12) (Row Lb) Row Lb incorrectly calculates the Annual Net RPS Position after Bank Optimization.

(13) (Rows B, Fd, and Ib) Compared to the 2018 Draft RPS Plan, row B was updated to reflect the RPS requirement percentages from SB 100, row Fd was updated to reflect additional RPS sales transactions executed before September 1, 2018, and row Ib was updated to show zero sales beginning in 2034 due to PG&E no longer having excess RPS bank.

(14) Potential impacts from SB 237 and SB 901 have not been incorporated due to time constraints and additional information needing to become available in order to accurately determine their impacts.

APPENDIX A.2

Alternate Renewable Net Short Calculations

March 15, 2019

Table 2: Alternative Renewable Net Short Calculation as of June 2018[15, 16]

Stochastically-Optimized Net Short Calculation Using PG&E Bundled Retail Sales Forecast and Corrections to Formulas

Variable	Calculation in Energy Division RNS Calculation Template	Revised Calculation Correcting Apparent Errors in Energy Division Template	Item	2011 Actuals	2012 Actuals	2013 Actuals	2011-2013	2014 Actuals	2015 Actuals	2016 Actuals	2014-2016	2017 Actuals	2018 Forecast	2019 Forecast	2020 Forecast	2017-2020	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2021 - 2024	2025 Forecast	2026 Forecast	2027 Forecast	2025 - 2027	2028 Forecast	2029 Forecast	2030 Forecast	2028 - 2030	2031 Forecast	2032 Forecast	2033 Forecast	2031 - 2033	2034 Forecast	2035 Forecast	2036 Forecast	2034 - 2036
			Forecast Year	-	-	-	CP1	-	-	-	CP2	-	-	-	-	CP3	-	-	-	-	CP4	-	-	-	CP5	-	-	-	CP6	-	-	-	CP7	-	-	-	CP8
			Annual RPS Requirement																																		
A			Bundled Retail Sales Forecast (Alternate)[1]	74,864	76,205	75,705	226,774	74,547	72,113	68,441	215,101	61,397	[redacted]	37,069	[redacted]	[redacted]	[redacted]	33,826	32,643	32,242	[redacted]	32,201	32,351	32,477	97,029	32,671	33,045	33,440	99,156	33,980	34,592	35,269	103,841	36,028	36,887	37,820	110,734
B			RPS Procurement Quantity Requirement (%)[2]	20.0%	20.0%	20.0%	20.0%	21.7%	23.3%	25.0%	23.3%	27.0%	29.0%	31.0%	33.0%	30.0%	35.8%	38.5%	41.3%	44.0%	39.9%	46.7%	49.3%	52.0%	49.3%	54.7%	57.3%	60.0%	57.3%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%
C	A*B		**Gross RPS Procurement Quantity Requirement (GWh)**	14,973	15,241	15,141	45,355	16,177	16,802	17,110	50,089	16,577	[redacted]	11,491	[redacted]	[redacted]	[redacted]	13,023	13,465	14,187	[redacted]	15,027	15,960	16,888	47,875	17,860	18,946	20,064	56,870	20,388	20,755	21,161	62,304	21,617	22,132	22,692	66,441
D			Voluntary Margin of Over-procurement[3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
E	C+D		**Net RPS Procurement Need (GWh)**	14,973	15,241	15,141	45,355	16,177	16,802	17,110	50,089	16,577	[redacted]	11,491	[redacted]	[redacted]	[redacted]	13,023	13,465	14,187	[redacted]	15,027	15,960	16,888	47,875	17,860	18,946	20,064	56,870	20,388	20,755	21,161	62,304	21,617	22,132	22,692	66,441
			RPS-Eligible Procurement																																		
Fa			Risk-Adjusted RECs from Online Generation[4]	14,699	14,513	17,212	46,424	20,207	21,285	22,551	64,042	22,345	20,520	20,700	20,428	83,993	20,076	17,608	16,856	16,578	71,118	16,417	15,883	15,627	47,927	15,570	14,999	14,928	45,497	14,164	13,620	12,384	40,168	11,120	10,013	9,333	30,467
Faa			Forecast Failure Rate for Online Generation (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fb			Risk-Adjusted RECs from RPS Facilities in Development[5]	-	-	-	-	-	-	-	-	-	26	588	769	1,384	985	981	977	974	3,916	968	963	959	2,889	956	950	945	2,851	941	939	932	2,811	563	501	384	1,447
Fbb			Forecast Failure Rate for RPS Facilities in Development (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fc			Pre-Approved Generic RECs	-	-	-	-	-	-	-	-	-	-	0	91	92	360	631	764	862	2,616	957	1,037	1,102	3,095	1,108	1,104	1,103	3,316	1,102	1,103	1,099	3,304	1,098	1,097	1,098	3,293
Fd			Executed REC Sales	-	-	(142)	(142)	(50)	-	(60)	(110)	(2,069)	(1,376)	(4,729)	(1,853)	(10,027)	(300)	-	-	-	(300)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F	Fa + Fb +Fc - Fd		Total RPS Eligible Procurement (GWh)[6]	14,699	14,513	17,069	46,281	20,157	21,285	22,491	63,932	20,276	19,170	16,559	19,436	75,442	21,120	19,220	18,597	18,414	77,351	18,341	17,883	17,687	53,911	17,635	17,053	16,976	51,664	16,207	15,662	14,415	46,284	12,781	11,611	10,815	35,207
F0			Category 0 RECs	14,651	13,049	14,163	41,863	16,899	17,408	17,914	52,222	14,804	13,873	10,985	12,447	52,109	13,284	11,199	10,903	10,675	46,060	10,556	10,046	9,816	30,418	9,768	9,240	9,195	28,204	8,524	8,420	7,789	24,733	7,158	6,711	6,701	20,569
F1			Category 1 RECs	48	1,464	2,906	4,418	3,257	3,876	4,577	11,710	5,471	5,873	6,724	6,990	25,058	7,837	8,022	7,694	7,738	31,291	7,785	7,837	7,871	23,494	7,866	7,812	7,781	23,460	7,683	7,242	6,625	21,551	5,623	4,900	4,114	14,637
F2			Category 2 RECs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F3			Category 3 RECs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
			Step 1 Result: Physical Net Short[7]																																		
Ga	F-E		**Annual Gross RPS Position (GWh)**	(274)	(728)	1,928	926	3,980	4,482	5,381	13,843	3,699	[redacted]	5,068	[redacted]	[redacted]	[redacted]	6,197	5,132	4,227	[redacted]	3,313	1,923	799	6,036	(225)	(1,893)	(3,088)	(5,206)	(4,181)	(5,093)	(6,746)	(16,021)	(8,836)	(10,521)	(11,877)	(31,234)
Gb	F/A		**Annual Gross RPS Position (%)**	19.6%	19.0%	22.5%	20.4%	27.0%	29.5%	32.9%	29.7%	33.0%	[redacted]	44.7%	[redacted]	[redacted]	[redacted]	56.8%	57.0%	57.1%	[redacted]	57.0%	55.3%	54.5%	55.6%	54.0%	51.6%	50.8%	52.1%	47.7%	45.3%	40.9%	44.6%	35.5%	31.5%	28.6%	31.8%

PG&E's Alternative RNS Table - Stochastic-Adjustment (2018-2033)[8]

Variable	Calculation in Energy Division RNS Calculation Template	Revised Calculation Correcting Apparent Errors in Energy Division Template	Item	2011 Actuals	2012 Actuals	2013 Actuals	2011-2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2014-2016	2017 Actuals	2018 Forecast	2019 Forecast	2020 Forecast	2017-2020	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2021 - 2024	2025 Forecast	2026 Forecast	2027 Forecast	2025 - 2027	2028 Forecast	2029 Forecast	2030 Forecast	2028 - 2030	2031 Forecast	2032 Forecast	2033 Forecast	2031 - 2033
			Step 2 Result: Stochastically-Adjusted Net Short (Physical Net Short + Stochastic Risk-Adjustment)[9]																														
Gd			**Stochastically-Adjusted Annual Gross RPS Position (GWh)**	(274)	(728)	1,928	926	3,980	4,482	5,381	13,843	3,699	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ge			**Stochastically-Adjusted Annual Gross RPS Position (%)**	19.6%	19.0%	22.5%	20.4%	27.0%	29.5%	32.9%	29.7%	33.0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
			Application of Bank																														
Ha	H - Hc (from previous year)	J - Hc (from previous year)	Existing Banked RECs above the PQR (The Bank at Beg. Of Period)[10,11]	-	(274)	(1,033)	-	861	4,815	9,274	861	14,630	18,200	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hb			RECs above the PQR added to Bank	(274)	(728)	1,928	926	3,980	4,482	5,381	13,843	3,699	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hc			Non-bankable RECs above the PQR	-	31	34	65	26	23	25	74	129	2	-	-	132	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
H	Ha+Hb		Gross Balance of RECs above the PQR	(274)	(1,002)	895	926	4,841	9,297	14,655	14,704	18,329	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ia			Planned Application of RECs above the PQR towards RPS Compliance	-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ib			Planned Sales of RECs above the PQR[12]	-	-	-	-	-	-	-	-	-	(693)	-	(216)	(909)	(1,769)	(2,069)	(2,069)	(2,069)	(7,976)	(2,069)	(2,069)	(2,069)	(6,207)	(2,069)	(2,069)	(2,069)	(6,207)	(2,069)	(2,069)	(2,069)	(6,207)
J	H-Ia-Ib	H-Ia+Ib	Net Balance of RECs above the PQR (The Bank at End of Period)[10]	(274)	(1,002)	895	926	4,841	9,297	14,655	14,704	18,329	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
J0			Category 0 RECs	-	-	-	-	657	1,237	2,019	2,067	2,067	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
J1			Category 1 RECs	-	-	895	926	4,184	8,060	12,636	12,636	16,261	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
J2			Category 2 RECs	-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
			Expiring Contracts																														
K			RECs from Expiring RPS Contracts[13]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	-	98	444	710	1,253	966	3,380	4,080	4,357	12,784	4,420	4,901	5,112	14,434	5,164	5,642	5,667	16,474	5,992	6,535	7,680	20,207
			Step 3 Result: Stochastically-Optimized Net Short (Stochastically-Adjusted Net Short + Application of Bank)[14]																														
La	Ga + Ia – Ib – Hc	Gd+Ia+Ib	**Annual Net RPS Position after Bank Optimization (GWh)[14]**	(274)	(728)	1,928	926	3,980	4,482	5,381	13,843	3,699	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lb	(F + Ia – Ib – Hc)/A	(C + La) / A	**Annual Net RPS Position after Bank Optimization (%)[14]**	19.6%	19.0%	22.5%	20.4%	27.0%	29.5%	32.9%	29.7%	33.0%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

General Table Notes: Values are shown in GWhs. Fields in grey are protected as Confidential under CPUC Confidentiality Rules.

(1) (Row A) PG&E uses its March 2018 internal bundled retail sales forecast less interdepartmental (metered usage at PG&E-owned facilities) and GTSR sales for its procurement decisions.

(2) (Row B) PG&E has included a voluntary 55% RPS target beginning in 2031 in its RPS position modeling for planning purposes.

(3) (Row D) As a portion of the Bank will be used as VMOP, Row D will remain zero. See Draft 2018 RPS Plan for a description of PG&E's VMOP.

(4) (Row Fa) "Online Generation" includes forecasted volumes from replacement contracts (i.e. ReMAT contracts replacing QF contracts) for facilities that are already online.

(5) (Row Fb) "In Development" includes forecasted volumes from phase-in projects. This is consistent with labeling in the RPS Database (which labels phase-in projects as "In Development" under "Overall Project Status").

(6) (Row F) Row F has subtracted 134 GWh of RECs associated with 2011 generation from the Hay Canyon Wind Facility and the Nine Canyon Wind Phase 3. These RECs are not being used for RPS compliance because they were not retired within the RPS statute's 36-month REC retirement deadline.

(7) (Step 1 Result: Physical Net Short) Rows Ga and Gb represent PG&E's physical net short based on PG&E's internal bundled retail sales forecast, as opposed to the IRP forecast provided in the RNS.

(8) The stochastic model optimizes from 2018 to 2033

(9) Step 2 Result: Stochastically-Adjusted Net Short (Physical Net Short+ Stochastic Risk-Adjustment) PG&E added rows Gd and Ge to the Alternative RNS in order to show the stochastically-adjusted physical net short, which incorporates the risks and uncertainties addressed in the stochastic model. For more details on PG&E's stochastically modeled risks, see the 2017 RPS Plan. This is prior to any application of the Bank.

(10) (Rows Ha and J) As PG&E's Alternative RNS incorporates additional risk-adjustments to the results from the Physical Net Short, the Bank sizes indicated in Rows Ha and J appear smaller than they are in Rows Ha and J of the RNS, which shows the non-stochastically-adjusted Bank size.

(11) (Rows Ha) At the beginning of each compliance period Row Ha subtracts previous compliance non-bankable volumes from the previous compliance period net balance of RECs. For example, the 2021 forecast for Row Ha is equivalent to the Row J in CP3 minus Row Hc in CP3.

(12) (Row Ib) The annual RPS sales volume forecast assumption is based on actual RPS sales completed in 2017 and is included for RPS position planning purposes. Row Ib is reduced by executed REC sales volumes included on Row Fd.

(13) (Row K) Row K now includes only expiring volumes from contracts as of June 2018.

(14) (Step 3 Result: Stochastically-Optimized Net Short (Stochastically-Adjusted Net Short + Application of Bank))

(a) Rows La and Lb represent the optimized net short that results from taking Row Gd (Step 2 Result) and then applying Bank usage. Bank can be used for either (i) compliance purposes (row Ia) or (ii) sales (Row Ib).

(b) Row La in the Alternative RNS does not match Row La in the RNS, because the RNS does not include Row Gd (Stochastically-Adjusted Net Short).

(15) (Rows B and Fd) Compared to the 2018 Draft RPS Plan, row B was updated to reflect the RPS requirement percentages from SB 100 and row Fd was updated to reflect additional RPS sales transactions executed before September 1, 2018.

(16) Potential impacts from SB 237 and SB 901 have not been incorporated due to time constraints and additional information needing to become available in order to accurately determine their impacts.

*Stochastic Results in Rows Gd-Lb reflect a July 2018 stochastic modeling vintage.

APPENDIX B

Procurement Information Related to Cost Quantification

March 15, 2019

Assumptions	
Table 1 (Actual Costs, $) Items	**Actual**
Rows 2 -- 8, 11 (2003-2017)[1,2,3,4]	Settled contract costs with all RPS-eligible contracts in PG&E's portfolio for 2003-2017
Row 9	For 2003-2011, capital costs are based on the net book value of PG&E's RPS-eligible units as of December 2011 multiplied by an assumed fixed charge rate equal to 14%. For 2012 through 2017, capital costs are based on the net book value of PG&E's RPS-eligible units as of December of that respective year multiplied by a fixed charge rate of 14%. PG&E's actual operation and maintenance (O&M) costs for each year (2003-2017) were added to each year's capital costs to calculate total costs.
Row 10	LCOE for each project multiplied by the project's historical generation
Row 13	PG&E actual bundled retail sales
Row 14	Total Cost / Bundled Retail Sales (Row 12 / Row 13)
Table 2 (Forecast Costs, $) Items	**Forecast**
Rows 2 -- 8, 11, 17 – 26[5]	PG&E's future expenditures on all RPS-eligible procurement and generation approved to date. 2018 forecast uses September 2017 vintage contract data and forward price curve data. 2019-2030 forecast uses June 2018 vintage contract data and forward price curve data. 2018 forecast data is consistent with the 2018 ERRA Forecast Application, filed at the CPUC on November 2, 2017.
Rows 9 and 24	UOG small hydro forecast revenue requirements
Rows 10 and 25	UOG solar forecast revenue requirements
Rows 12 and 27	PG&E REC sales revenue
Row 13 and 28[6]	Row 13 = Sum of Rows 2 through 11; Row 28 = Sum of Rows 16 through 25
Rows 14 and 29	PG&E bundled retail sales forecast
Rows 15 and 30	Total Cost / Bundled Sales
Row 31	Row 15 + Row 30
Table 3 (Actual Generation, MWh) Items	**Actual**
Rows 2 -- 11[1,3,4,5]	Generation (MWh) associated with payments for RPS-eligible deliveries
Table 4 (Forecast Generation, MWh) Items	**Forecast**
Rows 2 -- 11 and 15-25	Forecasted RPS-eligible generation (MWh) either (1) approved to date or (2) executed prior to July 2018 but pending Commission approval -- assumes no contract failure, and all contractual volumes are forecast at 100% of expected volumes. 2018 forecast uses September 2017 contract vintage. 2019-2030 uses June 2018 contract vintage.
Rows 12 and 26[7]	PG&E RECs sold volume

1 2016 Generation and Costs were updated to correctly account for GTSR Program impacts.

2 Row 5 includes the aggregate costs (specifically debt service and operation and maintenance) of PG&E's contract with Solano Irrigation District (SID) who supplies power from multiple hydro units, 100% of which are RPS-eligible. Yuba County Water Agency (YCWA) does not operate any RPS-eligible hydro units, therefore YCWA cost data is not relevant and thereby not included.

3 Energy volumes reported in Rows 2-8 represent the generation (MWh) associated with payments for RPS-eligible deliveries, which can differ from the energy volumes PG&E claims for the purposes of complying with California's RPS Program. For example, some RPS contracts require PG&E to only pay for RPS-eligible deliveries based on scheduled energy, but entitle PG&E to all green attributes generated and metered by the facility. Since compliance with California's RPS Program is based on metered generation, scheduled/paid volumes may not always match the metered/compliance volumes.

4 Costs for executed sales are a combination of geothermal and small hydro volumes. As the costs are a combined payment not divided by technology type, PG&E allocated technology specific costs based on the technology specific generation (MWh) of the sale contract.

5 UOG Small Hydro generation for 2013-2017 has been updated to reflect actual settlements data.

6 Total CPUC-Approved RPS-eligible Procurement and Generation Cost for 2018 through 2021 was updated to reflect additional RPS sales transactions executed before September 1, 2018 and to correct a calculation error in the draft 2018 RPS Plan filed on August 20, 2018.

7 RECs sold updated to reflect additional RPS sales transactions executed before September 1, 2018.

Note: As with any forecasting exercise, projections are predicated on a number of necessarily speculative assumptions and will be impacted by future events, including regulatory decisions resulting in different costs or rate treatments. Thus, PG&E cannot guarantee that the information contained in this summary will reflect actual future rates, revenue requirements, or sales.

Joint IOU Cost Quantification Table 1
(Actual Costs, $ Thousands)

		Actual RPS-Eligible Procurement and Generation Costs							
1	**Technology Type**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
2	Biogas	$25,762	$23,856	$25,623	$22,823	$24,126	$23,468	$27,306	$20,216
3	Biomass	$215,078	$217,923	$217,279	$222,125	$238,524	$259,957	$262,086	$263,994
4	Geothermal	$110,572	$111,778	$108,720	$118,523	$199,143	$282,227	$200,357	$260,053
5	Small Hydro	$60,984	$57,470	$80,340	$97,340	$63,161	$72,488	$52,053	$63,296
6	Solar PV	$0	$0	$0	$0	$0	$0	$2,554	$10,180
7	Solar Thermal	$0	$0	$0	$0	$0	$0	$0	$0
8	Wind	$65,244	$74,912	$56,891	$67,116	$98,203	$102,516	$199,475	$224,089
9	UOG Small Hydro	$44,936	$45,059	$46,526	$47,556	$47,933	$49,009	$47,567	$49,684
10	UOG Solar	$0	$0	$0	$0	$227	$452	$473	$1,498
11	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0	$0	$0
12	**Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 11]	**$522,576**	**$530,998**	**$535,380**	**$575,483**	**$671,317**	**$790,116**	**$791,870**	**$893,010**
13	Bundled Retail Sales [Thousands of kWh]	71,099,363	72,113,608	72,371,532	76,356,279	79,078,319	81,523,859	79,624,479	77,485,129
14	**Incremental Rate Impact[2]**	**0.73 ¢/kWh**	**0.74 ¢/kWh**	**0.74 ¢/kWh**	**0.75 ¢/kWh**	**0.85 ¢/kWh**	**0.97 ¢/kWh**	**0.99 ¢/kWh**	**1.15 ¢/kWh**

[1] The cost of Unbundled RECs are separated from their technology type and only reported in the Unbundled RECs row.
[2] Incremental Rate Impact is equal to Row 12 divided by Row 13 (in following table either Row 13 or 28 divided by Row 14 or 29, respectively). While the item is labeled "Incremental Rate Impact," the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

Joint IOU Cost Quantification Table 1 (continued)
(Actual Costs, $ Thousands)

		Actual RPS-Eligible Procurement and Generation Costs						
1	**Technology Type**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
2	Biogas	$16,776	$5,333	$5,063	$11,087	$22,283	$26,294	$31,071
3	Biomass	$245,622	$302,711	$299,205	$317,301	$286,766	$254,294	$202,416
4	Geothermal	$223,575	$209,854	$284,334	$324,050	$280,843	$273,751	$288,807
5	Small Hydro	$84,864	$54,140	$57,213	$45,522	$34,247	$64,646	$67,486
6	Solar PV	$33,370	$176,372	$504,860	$803,806	$949,556	$977,619	$952,115
7	Solar Thermal	$0	$0	$1,698	$173,856	$296,915	$340,074	$324,052
8	Wind	$340,517	$379,416	$424,764	$437,159	$422,102	$422,518	$401,179
9	UOG Small Hydro	$52,099	$51,572	$64,691	$66,066	$74,770	$108,830	$94,597
10	UOG Solar	$5,620	$27,093	$43,882	$52,426	$49,535	$48,527	$45,550
11	Unbundled RECs[1]	$823	$871	$677	$805	$705	$0.00	$0.00
12	**Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 11]	**$1,003,268**	**$1,207,361**	**$1,686,387**	**$2,232,077**	**$2,417,720**	**$2,516,552**	**$2,407,272**
13	Bundled Retail Sales [Thousands of kWh]	74,863,941	76,205,120	75,705,039	74,546,865	72,112,848	68,440,794	61,397,214
14	**Incremental Rate Impact[2]**	**1.34 ¢/kWh**	**1.58 ¢/kWh**	**2.23 ¢/kWh**	**2.99 ¢/kWh**	**3.35 ¢/kWh**	**3.68 ¢/kWh**	**3.92 ¢/kWh**

[1] The cost of Unbundled RECs are separated from their technology type and only reported in the Unbundled RECs row.
[2] Incremental Rate Impact is equal to Row 12 divided by Row 13 (in following table either Row 13 or 28 divided by Row 14 or 29, respectively). While the item is labeled "Incremental Rate Impact," the value should be interpreted as an estimate of a system average bundled rate for RPS-eligible procurement and generation, not a renewable "premium." In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

Joint IOU Cost Quantification Table 2
(Forecast Costs, $ Thousands)

		Forecasted Future Expenditures on RPS-Eligible Procurement and Generation Costs						
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
2	Biogas	$0	$0	$0	$0	$0	$0	$0
3	Biomass	$0	$0	$0	$0	$0	$0	$0
4	Geothermal	$0	$0	$0	$0	$0	$0	$0
5	Small Hydro	$0	$0	$0	$0	$0	$0	$0
6	Solar PV	$0	$0	$0	$0	$0	$0	$0
7	Solar Thermal	$0	$0	$0	$0	$0	$0	$0
8	Wind	$0	$0	$0	$0	$0	$0	$0
9	UOG Small Hydro	$0	$0	$0	$0	$0	$0	$0
10	UOG Solar	$0	$0	$0	$0	$0	$0	$0
11	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0	$0
12	REC Sales Revenue[2]	$0	$0	$0	$0	$0	$0	$0
13	**Total Executed But Not CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 12]	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
14	Bundled Retail Sales (Thousands of kWh)	47,641,472	37,069,052	[redacted]		33,825,688	32,643,034	32,242,266
15	**Incremental Rate Impact[3]**	**0.000 ¢/kWh**	**0.000 ¢/kWh**	**0.000 ¢/kWh**	**0.000 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**

[1] See footnote 1 from Table 1.
[2] Volumes in this row include a forecast of REC sales volumes that cannot feasibly be forecasted by technology type, due to the sales contract allowing for sale from a pool of resources that vary in technology types. To the extent sales are tied to specific resources where the technology is known, PG&E has incorporated these costs in the existing table structure to show a net cost.
[3] See footnote 2 from table 1.

Joint IOU Cost Quantification Table 2 (continued)
(Forecast Costs, $ Thousands)

		Forecasted Future Expenditures on RPS-Eligible Procurement and Generation Costs						
16	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
17	Biogas	$30,643	$40,084	$40,814	$41,086	$41,323	$41,255	$40,906
18	Biomass	$198,595	$198,966	$192,895	$192,732	$188,223	$142,787	$143,939
19	Geothermal	$187,174	$183,479	$173,386	$183,093	$13,561	$13,469	$13,422
20	Small Hydro	$56,990	$54,566	$46,642	$40,003	$34,006	$33,321	$33,574
21	Solar PV	$964,642	$1,033,877	$1,044,082	$1,046,016	$1,043,014	$1,039,406	$1,037,364
22	Solar Thermal	$317,390	$316,952	$318,073	$317,566	$317,488	$317,080	$317,372
23	Wind	$419,933	$404,429	$405,339	$398,761	$392,884	$373,210	$348,883
24	UOG Small Hydro	$114,023	$123,857	$132,614	$132,508	$138,033	$137,497	$142,673
25	UOG Solar	$51,664	$51,468	$50,765	$50,044	$49,324	$48,606	$47,891
26	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0	$0
27	REC Sales Revenue[2]	-$44,945	[redacted]	[redacted]	[redacted]	$0	$0	$0
28	**Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 17 through 27]	**$2,296,110**	[redacted]	[redacted]	[redacted]	**$2,217,856**	**$2,146,631**	**$2,126,024**
29	Bundled Retail Sales (Thousands of kWh)	47,641,472	37,069,052	[redacted]	[redacted]	33,825,688	32,643,034	32,242,266
30	**Incremental Rate Impact[3]**	**4.82 ¢/kWh**	[redacted]	**6.54 ¢/kWh**	**6.83 ¢/kWh**	**6.56 ¢/kWh**	**6.58 ¢/kWh**	**6.59 ¢/kWh**
31	**Total Incremental Rate Impact** [Row 15 + 30; Rounding can cause Row 31 to differ slightly from the sum of Row 15 and 30]	**4.82 ¢/kWh**	[redacted]	**6.54 ¢/kWh**	**6.83 ¢/kWh**	**6.56 ¢/kWh**	**6.58 ¢/kWh**	**6.59 ¢/kWh**

Joint IOU Cost Quantification Table 2 (continued)
(Forecast Costs, $ Thousands)

		Forecasted Future Expenditures on RPS-Eligible Procurement and Generation Costs					
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
2	Biogas	$0	$0	$0	$0	$0	$0
3	Biomass	$0	$0	$0	$0	$0	$0
4	Geothermal	$0	$0	$0	$0	$0	$0
5	Small Hydro	$0	$0	$0	$0	$0	$0
6	Solar PV	$0	$0	$0	$0	$0	$0
7	Solar Thermal	$0	$0	$0	$0	$0	$0
8	Wind	$0	$0	$0	$0	$0	$0
9	UOG Small Hydro	$0	$0	$0	$0	$0	$0
10	UOG Solar	$0	$0	$0	$0	$0	$0
11	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0
12	REC Sales Revenue[2]	$0	$0	$0	$0	$0	$0
13	**Total Executed But Not CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 2 through 12]	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
14	Bundled Retail Sales (Thousands of kWh)	32,201,311	32,350,733	32,476,785	32,671,183	33,044,570	33,440,380
15	**Incremental Rate Impact[3]**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**	**0.00 ¢/kWh**
16	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
17	Biogas	$40,402	$40,015	$39,307	$39,414	$37,242	$36,885
18	Biomass	$144,579	$145,332	$113,712	$108,925	$108,818	$109,027
19	Geothermal	$13,312	$13,254	$13,173	$13,120	$12,995	$12,920
20	Small Hydro	$33,357	$33,674	$34,057	$34,156	$29,294	$28,963
21	Solar PV	$1,034,128	$1,034,762	$1,030,738	$1,028,889	$1,020,750	$1,017,152
22	Solar Thermal	$317,731	$318,793	$318,560	$320,502	$319,693	$319,041
23	Wind	$340,302	$282,574	$282,686	$283,298	$246,776	$246,011
24	UOG Small Hydro	$150,334	$161,305	$166,255	$171,830	$175,321	$179,044
25	UOG Solar	$47,179	$46,162	$44,840	$43,524	$42,214	$40,913
26	Unbundled RECs[1]	$0	$0	$0	$0	$0	$0
27	REC Sales Revenue[2]	$0	$0	$0	$0	$0	$0
28	**Total CPUC-Approved RPS-Eligible Procurement and Generation Cost** [Sum of Rows 17 through 27]	**$2,121,324**	**$2,075,872**	**$2,043,327**	**$2,043,658**	**$1,993,104**	**$1,989,957**
29	Bundled Retail Sales (Thousands of kWh)	32,201,311	32,350,733	32,476,785	32,671,183	33,044,570	33,440,380
30	**Incremental Rate Impact[3]**	**6.59 ¢/kWh**	**6.42 ¢/kWh**	**6.29 ¢/kWh**	**6.26 ¢/kWh**	**6.03 ¢/kWh**	**5.95 ¢/kWh**
31	**Total Incremental Rate Impact** [Row 15 + 30; Rounding can cause Row 31 to differ slightly from the sum of Row 15 and 30]	**6.59 ¢/kWh**	**6.42 ¢/kWh**	**6.29 ¢/kWh**	**6.26 ¢/kWh**	**6.03 ¢/kWh**	**5.95 ¢/kWh**

[1] See footnote 1 from Table 1.
[2] Volumes in this row include a forecast of REC sales volumes that cannot feasibly be forecasted by technology type, due to the sales contract allowing for sale from a pool of resources that vary in technology types. To the extent sales are tied to specific resources where the technology is known, PG&E has incorporated these costs in the existing table structure to show a net cost.
[3] See footnote 2 from table 1.

Joint IOU Cost Quantification Table 3
(Actual Generation, MWh)

		Actual RPS-Eligible Procurement and Generation (MWh)							
1	**Technology Type**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
2	Biogas	364,745	333,897	366,514	300,943	293,147	280,795	342,362	306,909
3	Biomass	2,839,795	2,961,633	2,858,643	2,770,398	2,751,813	2,813,819	3,122,048	2,990,615
4	Geothermal	1,674,702	1,753,043	1,687,360	1,790,870	2,701,970	3,350,232	3,411,798	3,766,700
5	Small Hydro	1,269,233	1,096,183	1,457,339	1,760,707	927,879	945,921	937,626	1,092,707
6	Solar PV	6	4	4	3	1	1	21,706	58,593
7	Solar Thermal	0	0	0	0	0	0	0	0
8	Wind	940,239	1,078,579	874,204	1,019,451	1,374,337	1,439,796	2,557,988	2,981,660
9	UOG Small Hydro	1,382,934	1,267,084	1,403,130	1,437,196	984,607	993,266	1,103,017	1,157,077
10	UOG Solar	0	0	0	0	225	445	504	4,642
11	Unbundled RECs	0	0	0	0	0	0	0	0
12	**Total CPUC-Approved RPS-Eligible Procurement and Generation** [Sum of Rows 2 through 11]	8,471,654	8,490,423	8,647,195	9,079,568	9,033,979	9,824,276	11,497,048	12,358,903

Joint IOU Cost Quantification Table 3 (continued)
(Actual Generation, MWh)

		Actual RPS-Eligible Procurement and Generation (MWh)						
1	**Technology Type**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
2	Biogas	284,129	112,153	85,706	112,161	212,975	245,242	278,471
3	Biomass	3,043,656	3,158,131	3,055,370	3,226,904	2,814,468	2,709,612	1,935,092
4	Geothermal	3,780,954	3,807,728	3,687,236	3,870,952	3,646,936	3,719,139	2,796,245
5	Small Hydro	1,457,714	863,606	652,953	400,300	304,368	941,004	953,601
6	Solar PV	179,171	1,006,145	3,358,366	5,266,030	6,260,429	6,517,251	6,480,621
7	Solar Thermal	0	0	20,581	878,905	1,557,412	1,750,981	1,464,827
8	Wind	4,395,377	4,515,452	4,924,052	5,358,546	5,418,594	5,400,931	5,033,470
9	UOG Small Hydro	1,254,638	948,734	929,639	580,990	537,838	891,763	918,916
10	UOG Solar	26,790	165,656	279,500	336,905	318,582	322,415	297,758
11	Unbundled RECs	102,888	108,874	101,256	100,581	88,107	0	0
12	**Total CPUC-Approved RPS-Eligible Procurement and Generation** [Sum of Rows 2 through 11]	14,525,317	14,686,479	17,094,659	20,132,274	21,159,709	22,498,340	20,159,001

Joint IOU Cost Quantification Table 4
(Forecast Generation, MWh)

		Forecasted Future RPS-Deliveries (MWh)						
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
2	Biogas	0	0	0	0	0	0	0
3	Biomass	0	0	0	0	0	0	0
4	Geothermal	0	0	0	0	0	0	0
5	Small Hydro	0	0	0	0	0	0	0
6	Solar PV	0	0	0	0	0	0	0
7	Solar Thermal	0	0	0	0	0	0	0
8	Wind	0	0	0	0	0	0	0
9	UOG Small Hydro	0	0	0	0	0	0	0
10	UOG Solar	0	0	0	0	0	0	0
11	Unbundled RECs	0	0	0	0	0	0	0
12	RECs Sold[1]	0	0	0	0	0	0	0
13	**Total Executed But Not CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 2 through 12]	0	0	0	0	0	0	0
14	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
15	Biogas	273,087	289,140	293,484	295,170	296,417	295,969	292,961
16	Biomass	1,750,181	1,734,496	1,623,358	1,595,913	1,545,220	1,140,191	1,143,029
17	Geothermal	2,319,550	2,318,642	2,324,162	2,316,843	152,256	151,369	150,971
18	Small Hydro	800,178	709,446	612,218	504,801	416,856	395,403	395,100
19	Solar PV	7,026,970	7,928,433	8,035,762	8,174,497	8,120,917	8,067,589	8,031,245
20	Solar Thermal	1,762,261	1,762,261	1,765,243	1,762,261	1,762,261	1,762,261	1,765,243
21	Wind	5,263,245	5,064,235	5,063,470	4,939,188	4,824,782	4,551,309	4,300,270
22	UOG Small Hydro	1,160,922	1,156,476	1,155,575	1,151,996	1,152,123	1,150,851	1,155,088
23	UOG Solar	326,400	324,702	323,731	321,333	319,661	317,998	317,048
24	Unbundled RECs	0	0	0	0	0	0	0
25	RECs Sold[1]	-926,962	-4,730,151	-1,853,699	-300,000	0	0	0
26	**Total CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 15 through 25]	19,755,832	16,557,680	19,343,305	20,762,000	18,590,493	17,832,941	17,550,954

[1] Volumes in this row include a forecast of REC sales volumes that cannot feasibly be forecasted by technology type, due to the sales contract allowing for sale from a pool of resources that vary in technology types. To the extent sales are tied to specific resources where the technology is known, PG&E has incorporated these costs in the existing table structure to show a net cost.

Joint IOU Cost Quantification Table 4 (continued)
(Forecast Generation, MWh)

		Forecasted Future RPS-Deliveries (MWh)					
1	**Executed But Not CPUC-Approved RPS-Eligible Contracts**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
2	Biogas	0	0	0	0	0	0
3	Biomass	0	0	0	0	0	0
4	Geothermal	0	0	0	0	0	0
5	Small Hydro	0	0	0	0	0	0
6	Solar PV	0	0	0	0	0	0
7	Solar Thermal	0	0	0	0	0	0
8	Wind	0	0	0	0	0	0
9	UOG Small Hydro	0	0	0	0	0	0
10	UOG Solar	0	0	0	0	0	0
11	Unbundled RECs	0	0	0	0	0	0
12	RECs Sold	0	0	0	0	0	0
13	**Total Executed But Not CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 2 through 12]	0	0	0	0	0	0
14	**CPUC-Approved RPS-Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
15	Biogas	287,348	282,645	276,908	277,653	265,875	263,659
16	Biomass	1,140,191	1,137,162	932,625	902,063	899,841	899,841
17	Geothermal	149,611	148,740	147,873	147,484	146,156	145,305
18	Small Hydro	388,048	387,065	387,003	383,479	336,873	329,754
19	Solar PV	7,956,168	7,923,129	7,871,437	7,836,313	7,750,575	7,693,711
20	Solar Thermal	1,762,261	1,762,261	1,762,261	1,765,243	1,762,261	1,762,261
21	Wind	4,227,513	3,755,541	3,755,541	3,762,996	3,339,615	3,329,172
22	UOG Small Hydro	1,153,671	1,152,292	1,152,310	1,157,011	1,153,431	1,152,787
23	UOG Solar	314,699	313,062	311,434	310,503	308,203	306,600
24	Unbundled RECs	0	0	0	0	0	0
25	RECs Sold	0	0	0	0	0	0
26	**Total CPUC-Approved RPS-Eligible Deliveries** [Sum of Rows 15 through 25]	17,379,511	16,861,897	16,597,392	16,542,747	15,962,830	15,883,091

APPENDICES C.1 – C.3

Redacted in Entirety

March 15, 2019

APPENDICES C.4 – C.5

Redacted in Entirety

March 15, 2019

APPENDIX D

Other Modeling Assumptions Informing Quantitative Calculation

March 15, 2019

Appendix D – Other Modeling Assumptions Informing Quantitative Calculation

Other Modeling Assumptions Informing Quantitative Calculation[2]

<table>
<tr><th colspan="2">Assumptions Related to Procurement Quantity Requirement</th></tr>
<tr><td>Compliance Periods</td><td>

As implemented by Decision (“D.”) 11-12-020 and D.16-12-040, and as amended by Senate Bill (“SB”) 100 (2018),[1] the Renewables Portfolio Standard (“RPS”) statute requires retail sellers of electricity to meet the following RPS procurement quantity requirements beginning on January 1, 2011:

An average of twenty percent of the combined bundled retail sales during the first compliance period (2011-2013).
Sufficient procurement during the second compliance period (2014-2016) that is consistent with the following formula: (.217 * 2014 retail sales) + (.233 * 2015 retail sales) + (.25 * 2016 retail sales).
Sufficient procurement during the third compliance period (2017-2020) that is consistent with the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail sales).
Sufficient procurement during the fourth compliance period (2021-2024) that is consistent with the following formula: (.358 * 2021 retail sales) + (.385 * 2022 retail sales) + (.413 * 2023 retail sales) + (.44 * 2024 retail sales).
Sufficient procurement during the fifth compliance period (2025-2027) that is consistent with the following formula: (.467 * 2025 retail sales) + (.493 * 2026 retail sales) + (.52 * 2027 retail sales).
Sufficient procurement during the sixth compliance period (2028-2030) that is consistent with the following formula: (.547 * 2028 retail sales) + (.573 * 2029 retail sales) + (.6 * 2030 retail sales).

60 percent of bundled retail sales in 2031 and all years thereafter.

</td></tr>
</table>

1 PG&E is assuming, for purposes of this 2018 RPS Plan, that the California Public Utilities Commission will implement the SB 100 revised targets in the same “straight-line” manner as it implemented prior versions of the statutory RPS targets.

2 All assumptions in this table reflect a June 2018 data vintage (with the exception of the internal sales forecast, which uses a March 2018 vintage) which is consistent with the data vintage of Appendices A1–A2.

Appendix D – Other Modeling Assumptions Informing Quantitative Calculation

Assumptions Related to Forecasted Generation	
Non-Qualifying Facility (“QF”) Projects *Contracts Executed Post-2002*	• Except for the “OFF/Closely Watched” contract category (see Section 4), all non-QF signed contracts are assumed to deliver at 100% of contract volumes, and deliveries commence within the allowed delay provisions in the contract.
QF Non-Hydro Projects *Contracts Executed Pre-2002*	• Forecast is typically based on an average of the three most recent calendar year deliveries. • Year 2018 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available.
QF Hydro *Pre-2002 QF, Irrigation District, and Legacy Utility-Owned Assets*	• The forecast for hydro QFs is typically based on historical production, normalized for average year conditions, and then adjusted to reflect PG&E’s latest internal hydro outlook. • Projects are forecasted at 79% of average water year generation for 2018 (based on PG&E’s June 2018 vintage internal hydro delivery forecast) and reverting to average water years in later years. • Year 2018 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available.
Non-QF Hydro *Utility Owned Generation (“UOG”) and Irrigation District Water Authority (“IDWA”)*	• Forecasts reflect PG&E’s best available projections for hydro conditions. • Projects are forecasted at 79% of average water year generation for 2018 (based on PG&E’s June 2018 vintage internal hydro delivery forecast) and reverting to average water years in later years. • Year 2018 deliveries: Recorded meter data replaces forecasted deliveries for all projects as it becomes available.

Appendix D – Other Modeling Assumptions Informing Quantitative Calculation

<table>
<tr><th colspan="2">Assumptions Related to Forecasted Generation</th></tr>
<tr><td>Future Volumes from Pre-Approved Programs</td><td>Renewable Market Adjusting Tariff (ReMAT)
• All deliveries from executed contracts are assumed at 100% of contract volumes.
• Modeled start date for generic volumes assumed to begin 2019 and ramp up until 2027, reaching a total of ~122MW.

Bioenergy Market Adjusting Tariff (BioMAT)
• All deliveries from executed contracts are assumed at 100% of contract volumes.
• Modeled start date for generic volumes assumed to begin 2020 and ramp up until 2023, reaching a total of ~91 MW.

PV Originally Authorized for PG&E Photovoltaic Program
• All deliveries from executed contracts are assumed at 100% of contract volumes.
• For planning purposes, PG&E has assumed that a total of 77.5 MW will be coming online in 2021[3]</td></tr>
<tr><td>Re-contracting</td><td>• For the following reasons this risk-adjusted forecast does not assume that expiring volumes are retained:
1. PG&E does not yet have contractual commitments for these expiring volumes;
2. A number of the expiring contracts are with aging generating facilities with limited remaining useful life;
3. Contract-renewal bids may not be competitive with offers for new projects received in future solicitations; and
4. PG&E’s current bundled load forecast does not support a re-contracting assumption.
• Re-contracting is not precluded by this assumption, but rather it reflects that re-contracting will be considered in the future side-by-side with procurement of other new resources.
• This forecasting methodology (i.e. not assuming any re-contracting) is consistent with PG&E’s Annual RPS compliance filing that only shows PG&E’s current contractual commitments.</td></tr>
</table>

3 This assumption is based on a modeling vintage of June 2018.

Appendix D – Other Modeling Assumptions Informing Quantitative Calculation

Assumptions Related to Forecasted Generation	
Green Tariff Shared Renewables (“GTSR”)	• PG&E allocates small amounts of generation from RPS-eligible resources to serve initial GTSR enrollees until new incremental resources procured for the GTSR program are sufficient to meet program needs. • When calculating PG&E’s RPS position, GTSR volumes are removed from PG&E’s RPS-eligible retail sales forecast. • PG&E incorporates any GTSR related impacts on its RPS–eligible generation into its RNS tables through 2036.

Banking	• PG&E assumes that: (1) grandfathered (pre-June 1, 2010) short-term products are bankable, and (2) that banked volumes may be applied in any period onward.
	  ○ PG&E’s accounting is consistent with the direction set forth in D.12-06-038 for compliance periods one and two.
	  Beginning with compliance period three, PG&E’s accounting is consistent with the direction set forth in D.17-06-026.

RPS Sales	• PG&E has developed a framework to assess whether to hold or sell excess RPS volumes, which will allow PG&E to rebalance its RPS portfolio to better align its RPS position with its RPS need. The framework will be used to determine future sales of bankable RPS volumes. Details of PG&E’s sales framework are discussed in Appendix G.

Appendix D – Other Modeling Assumptions Informing Quantitative Calculation

Assumptions Related to Forecasted Sales	
Bundled Retail Sales *RNS (App. A.1)*	• Forecasts of retail sales for the first five years of the forecast (2018-2022) were generated by PG&E's *Load Forecasting and Research* team in March 2018, and may be updated throughout the year as additional data becomes available. • Forecasts of retail sales beyond the first five years are sourced from the 2017-2018 IRP Cycle forecast. The IRP has been identified as the successor to the LTPP proceeding planning process.
Bundled Retail Sales *Alternate RNS (App. A.2)*	• Forecasts of retail sales were generated by PG&E's *Load Forecasting and Research* team in March 2018, and may be updated throughout the year as additional data becomes available.

APPENDIX E

Responses to Renewable Net Short Questions

March 15, 2019

Appendix E – Responses to Renewable Net Short Questions

The following presents Pacific Gas and Electric Company's (PG&E) responses to questions set forth in the May 21, 2014 *Administrative Law Judge's Ruling on Renewable Net Short*.

<u>RPS Compliance Risk</u>

1. How do current and historical performance of online resources in your RPS portfolio impact future projections of RPS deliveries and your subsequent RNS?

PG&E considers historical performance of online resources in both of its models. First, it considers this performance in developing the generation forecast in its deterministic model. Appendix D to the RPS Plan discusses the assumptions PG&E has used to model future deliveries from RPS projects.

In addition, within its stochastic model, PG&E considers RPS generation variability based on historical performance of each resource type. A probabilistic distribution is built for each resource based on its calculated coefficient of variation. This captures additional RPS generation variability above and beyond the variances that are captured in the deterministic model. The RPS Plan describes in more detail how historic generation variability from each resource is used as an input to the stochastic model.

2. Do you anticipate any future changes to the current bundled retail sales forecast? If so, describe how the anticipated changes impact the RNS.

PG&E's retail sales are impacted by many factors, including weather, economic growth or recession, technological change, energy efficiency, Direct Access and Community Choice Aggregator participation levels, and distributed generation. PG&E's most recent Sales Forecast used in the RPS Plan is a March 2018 updated internal sales forecast. It is important to emphasize that PG&E's Alternative Scenario is a forecast including a number of assumptions regarding events which may or may not occur. PG&E updates the bundled load forecasts at least annually to reflect any new events and capture actual load changes. As described in more detail in its RPS Plan, PG&E uses its stochastic model to simulate a range of potential retail sales forecasts. Changes in retail sales tend to be variable and persistent, making uncertainty around retail sales one of the largest drivers of RPS outcomes, particularly over time.

3. Do you expect curtailment of RPS projects to impact your projected RPS deliveries and subsequent RNS?

To the extent that RPS projects are economically bid and do not clear the market, or are curtailed for system reliability, PG&E expects that curtailment will impact its RNS. As described in the RPS Plan, the stochastic model evaluates uncertainty associated with RPS generation variability, including assumptions of future levels of RPS curtailment.

4. Are there any significant changes to the success rate of individual RPS projects that impact the RNS?

PG&E assumes a volumetric success rate for all executed in-development projects in its RPS portfolio of 100% of total contracted volumes. This rate continues its general trend of increasing from 60% in RPS Plans prior to 2012, to 78% in PG&E's 2012 RPS Plan, to 100% in PG&E's 2013 RPS Plan, to 87% in PG&E's 2014 RPS Plan, 99 percent in PG&E's 2015 RPS Plan, and 100% in PG&E's 2016 RPS Plan to present.[1] This success rate is evolving and highly dependent on the nature of PG&E's portfolio and the general conditions in the renewable energy industry.

In addition, to model the project failure variability inherent in project development, PG&E adds additional success rate assumptions to it stochastic model, which assume that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. These assumptions are used in order to calculate its stochastically-optimized net short. See the answer to question #5 below for details on these new assumptions.

5. As projects in development move towards their COD, are there any changes to the expected RPS deliveries? If so, how do these changes impact the RNS?

Yes. PG&E may adjust the expected delivery volumes in its deterministic model for RPS projects in development for various reasons. For example, counterparties may make adjustments to their project design, such as decreasing total project capacity, which may lead to changes in expected generation. Counterparties may also experience project delays which impact the delivery date for projects, shifting generation volumes further into the future. In extreme cases, PG&E may categorize projects experiencing considerable development challenges as "Closely Watched" and would in those cases reduce the expected delivery volumes from those projects to zero in its deterministic model. Moving a project to the "Closely Watched" category would therefore decrease future delivery volumes and increase the RNS. PG&E has an extensive program for monitoring the development status of RPS-eligible projects, and the deterministic model is updated regularly to reflect any relevant status changes.

In addition, PG&E further reduces its anticipated deliveries from future projects in its stochastic model, as described in more detail in its RPS Plan. To model the project failure variability inherent in project development, PG&E assumes that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. PG&E assigns a probability of project success for new, yet-to-be-built projects equal to [redacted].
For example, a project scheduled to come online in five years or more is assumed to have a [redacted] or [redacted] chance of success. This success rate is based on experience, and although PG&E's current existing portfolio of projects may have higher rates of success, the actual success rate for projects in the long-term may be higher or lower. Appendix C.2 shows PG&E's simulated failure rate for the period 2018-2030.

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1 PG&E's success rate discussed is more reflective of the success rate of its overall portfolio, and so this percentage does not convey that PG&E has no projects failing. Specifically, since almost all of PG&E's in-development projects are volumes procured through mandated programs with set targets, any projects that fail will be replaced through future solicitation rounds. Therefore, the effect on PG&E's portfolio is that the amount of volumes projected has a very high project success rate, given that any failed project will be replaced with a new project, until the volumes come online.

Please see section 7.2.5, Table 7-3 for a comparison of uncertainty assumptions between PG&E's deterministic and stochastic models.

6. What is the appropriate amount of RECs above the PQR to maintain? Please provide a quantitative justification and elaborate on the need for maintaining banked RECs above the PQR.

As described in Sections 8 and 9, PG&E plans to use a portion of its Bank as a Voluntary Margin of Over-Procurement (VMOP) to manage additional risks and uncertainties accounted for in the stochastic model. PG&E performed a simulation of variability in PG&E's future generation and RPS compliance targets over [redacted] years—i.e., the amount of RPS generation ("delivery") net of RPS compliance targets ("target")—and found that a Bank size of at least [redacted] is the minimum Bank necessary to maintain a cumulative non-compliance risk of no greater than [redacted].[2] However, because the stochastic model inputs change over time, forecasts of the Bank size will also change, so these estimates should be seen as a point forecast rather than a static target. Please see Section 8 for additional information.

7. What are your strategies for short-term management (10 years forward) and long-term management (10-20 years forward) of RECs above the PQR? Please discuss any plans to use RECs above the PQR for future RPS compliance and/or to sell RECs above the PQR.

As described in Sections 7 and 8, PG&E uses its stochastic model to optimize its procurement. This model currently forecasts Bank levels through [redacted], projecting that PG&E's forecasted Bank size [redacted] GWh by [redacted]. Under this projection, [redacted] Bank will be maintained as VMOP to manage additional risks and uncertainties associated with managing an RPS portfolio.

In the long-term, PG&E will use Renewable Energy Credits (REC) above the Procurement Quantity Requirements (PQR), as needed, to maintain an adequate Bank, as determined by the deterministic and stochastic model or similar means, in order to manage additional risks and uncertainties.

PG&E's optimization strategy includes planned sales of RPS products, so long as certain conditions set forth in PG&E's RPS Sales Framework are met.[3]

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2 As PG&E discusses in Appendix G, when considering sales, PG&E considers [redacted]

3 *See* Appendix G to the RPS Plan (RPS Sales Framework) and Section 4 of the main RPS Plan.

VMOP

8. Provide VMOP on both a short-term (10 years forward) and long-term (10-20 years forward) basis. This should include a discussion of all risk factors and a quantitative justification for the amount of VMOP.

As discussed in Sections 7 and 8, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model. While PG&E's proposed RPS Sales Framework [redacted], PG&E believes it would be imprudent to use its entire projected Bank [redacted]. In that case, a portion of the Bank should be used to cover unexpected demand and supply variability and project failure or delay exceeding forecasts from projects not yet under contract. When used as VMOP, the Bank will help to avoid long-term over-procurement above the RPS targets, and will thus reduce long-term costs of the RPS Program.

9. Please address the cost-effectiveness of different methods for meeting any projected VMOP procurement need, including application of forecast RECs above the PQR.

As discussed in Sections 6 and 7, PG&E's stochastic model optimizes its results to inform its RPS procurement strategy, which includes using a portion of the Bank as VMOP, to achieve the lowest cost possible given a specified risk of non-compliance. The model suggests a specific level of procurement and resulting Bank usage for each year. PG&E then uses these model results as a tool to guide its actual procurement strategy. While the model provides other possible VMOP usage given a specific level of non-compliance risk, these paths would not be minimum cost under the model's assumptions.

PG&E does not approach RPS procurement and compliance as a speculative enterprise and so has not modeled or otherwise proposed such strategies in this Plan. However, PG&E will consider selling surplus RPS volumes if it can still maintain an adequate Bank and if market conditions are favorable. PG&E discusses a framework to assess whether to hold or to sell excess RPS volumes in Appendix G.

Cost-Effectiveness

10. Are there cost-effective opportunities to use banked RECs above the PQR for future RPS compliance in lieu of additional RPS procurement to meet the RNS?

As discussed in greater detail in Sections 7, 8, and 9 of this Plan, [redacted].

Overall, PG&E can best meet the objective to minimize customer costs when it can thoroughly examine and take advantage of all cost-effective commercial opportunities to purchase or sell RPS-eligible products consistent with its RPS Plan on a going-forward basis, continually adapting to these uncertain variables. PG&E will continue to use the stochastic model to help guide decisions around minimum Bank size needed to maintain PG&E's non-compliance risk of [redacted] for the period of [redacted]. PG&E will then procure any needed incremental volumes ratably over time.

11. How does your current RNS fit within the regulatory limitations for PCCs? Are there opportunities to optimize your portfolio by procuring RECs across different PCCs?

PG&E's current RPS portfolio consists of primarily Category 0 and 1 RECs. Category 3 products are a limited, but potentially important, part of PG&E's procurement strategy, as they may provide a low-cost compliance option for PG&E's customers while at the same time potentially mitigating integration and other operational challenges associated with incremental procurement from typical Category 1 or Category 2 procurement.

While PG&E seeks opportunities across all product categories to procure the most cost-effective resources to achieve the RPS requirements, the pre-Senate Bill (SB) 350 restrictions on banking of excess procurement have limited PG&E's ability to fully optimize its portfolio.

The changes to the RPS program under SB 350 enable banking of all Category 0 and 1 RECs of any duration, beginning in the 2021-2024 compliance period for all entities, or as early as the 2017-2020 compliance period for entities, like PG&E, that elect to comply early with the new SB 350 minimum long-term requirements. In addition, all retired Category 2 and Category 3 RECs that fall within the portfolio balance requirements are eligible to be counted towards PG&E's RPS procurement quantity requirement for the compliance period whether the RECs are associated with short-term or long-term contracts.

APPENDIX F.1

2019 Bundled RPS Energy Sale – Solicitation Protocol

March 15, 2019

Pacific Gas and Electric Company®

2019 Bundled RPS Energy Sale - Solicitation Protocol

Issuance Date: __________, 2019

Table of Contents

LIST OF ATTACHMENTS

I. Overview

A. Overview

Pacific Gas and Electric Company ("PG&E") is issuing the 2019 Bundled Renewable Portfolio Standard ("RPS") Energy Sale Solicitation ("Solicitation" or "2019 Bundled RPS Sale") to solicit bids ("Bids") from participants ("Participants" or "Bidders") for bundled RPS-eligible energy and associated Renewable Energy Credits ("REC") (collectively, "Product") pursuant to a confirmation ("Agreement"). This Solicitation protocol ("Solicitation Protocol") describes the process by which PG&E seeks, evaluates, and accepts Bids in this solicitation from winning Bidders ("Buyers").

The 2019 Bundled RPS Sale complies with PG&E's 2018 RPS Plan, which was approved by the California Public Utilities Commission ("CPUC" or "Commission") in Decision (D.) 19-02-007).

Subject to Bid pricing and other factors in this Solicitation Protocol, PG&E seeks to sell a volume of Product commensurate with revenue of Bids received.

PG&E will make all sales according to the terms and conditions set forth in the Agreement. This Solicitation Protocol sets forth the procedures a Bidder must follow in order to participate in the Solicitation. Capitalized terms used in this Solicitation Protocol, but not otherwise defined herein, have the meanings set forth in the Agreement.

B. Bundled RPS Energy Sale Solicitation Communication

PG&E has established the 2019 Bundled RPS Energy Sale Solicitation website at http://www.pge.com/rfo under "2019 Bundled RPS Energy Sale Solicitation." This site will be where Bidders register and where all Solicitation documents, information, announcements and questions and answers are posted and available to Bidders.

To promote accuracy and consistency of the information provided to all Bidders, PG&E encourages Bidders to submit any inquiries via e-mail to RECSolicitations@pge.com for matters related to the Solicitation. With respect to matters of general interest raised by any Bidder, PG&E may, without reference to the specific Bidder raising such matter or initiating the inquiry, post the questions and responses on its website. PG&E may, in its sole discretion, decline to respond to any email or other inquiry.

Any exchange of material information regarding this Solicitation between Bidder and PG&E must be submitted to both PG&E and the Independent Evaluator ("IE"). The IE is an independent, third party evaluator who is required by CPUC D.04-12-048 to ensure this Solicitation is conducted in a reasonable and neutral manner.

C. Schedule

The Solicitation schedule is subject to change to conform to any CPUC requirements but otherwise is at the discretion of PG&E. PG&E will post any schedule changes on PG&E's Solicitation website. Also, as further described below, Bidders may register at PG&E's Request for Offer (RFO) website to receive notice of these and other Solicitation changes by electronic mail. PG&E will have no liability or responsibility to any Bidder for any change in the schedule or for failing to provide notice of any change.

The schedule for this Solicitation is (all times are in Pacific Prevailing Time):

Table 1: 2019 Bundled RPS Energy Sale Solicitation Schedule of Events

Date/Time	Event
Ongoing	Bidders may register online at PG&E's RFO website to receive notices regarding the Solicitation.
TBD	PG&E issues the Solicitation.
TBD	Bids Due. Bid(s) must be submitted to the online platform at Power Advocate.
TBD	PG&E notifies qualified Bidders.
TBD	PG&E and qualified Bidders execute Agreement, which shall be subject to "CPUC Approval," as provided in the Agreement.
No later than 60 days after execution	PG&E submits Agreements for CPUC Approval.

D. Events in the Solicitation Schedule

a. Registration. Bidders may register online to receive announcements and updates about this Solicitation through www.pge.com/rfo.

b. Issuance. PG&E will issue the Solicitation and post the Solicitation Protocol, form of Agreement, and all other solicitation materials on the Solicitation website.

c. Bids Due. Bids must be submitted via Power Advocate and must include all of the documents described in Section IV, Required Information. By submitting a Bid(s) and responding to this Solicitation, the Bidder agrees to be bound by all of the terms, conditions and other provisions of this Solicitation and any changes or supplements to it that may be issued by PG&E.

d. PG&E Selects Bids. Selected Bids ("Selected Bids") will be notified via email. PG&E will select Bids according to the evaluation criteria described in Section III, Evaluation Criteria. Bids beyond the Selected Bids may be placed on a waitlist to be selected in order of evaluation results and selection constraints, should any Selected Bids fail to complete the Solicitation process.

e. Completion of Agreement. PG&E will complete Agreement with Participants with Selected Bids.

f. Execution and Regulatory Approval. Once PG&E and the Participants with Selected Bids execute Agreements, if any, resulting from this Solicitation, PG&E will submit all such Agreements to the CPUC for approval via an advice letter filing. Additional regulatory approval information is provided in Section VII, Regulatory Approval.

E. Disclaimers for Rejecting Bids and/or Terminating this Solicitation

This Solicitation does not constitute an offer to sell and creates no obligation to execute any Agreement or to enter into a transaction under an Agreement as a consequence of the Solicitation. PG&E shall retain the right at any time, at its sole discretion, to reject any Bid on the grounds that it does not conform to the terms and conditions of this Solicitation and reserves the right to request information at any time during the Solicitation process.

PG&E retains the discretion, subject to, if applicable, the approval of the CPUC, to: (a) reject any Bid for any reason, including but not limited to the basis that a Bid is the result of market manipulation or is not cost-competitive or any other applicable reason; (b) modify this Solicitation and the form Agreement as it deems appropriate to implement the Solicitation and to comply with applicable law or other decisions or direction provided by the CPUC; and (c) terminate the Solicitation should the CPUC not authorize PG&E to sell the Product in the manner proposed in this Solicitation. In addition, PG&E reserves the right to either suspend or terminate this Solicitation at any time if such suspension is required by or with the approval of the CPUC. PG&E will not be liable in any way, by reason of such withdrawal, rejection, suspension, termination or any other action described in this Solicitation Protocol to any Bidder, whether submitting a Bid or not.

II. Solicitation Product and Goals

PG&E is seeking to sell Product with the exact volume to be determined based on the total revenue of bids received.

A. Product Attributes

1. Bundled RPS-eligible energy and associated RECs from resources in PG&E's portfolio.
2. Price: NP15, ZP26 and/or SP15 Index + REC Price to be specified by Buyer.
3. Location: Buyer to choose energy deliveries at NP15 Trading Hub, ZP26 Trading Hub, or SP15 Trading Hub.
4. Scheduled Energy Deliveries: Energy deliveries may be in any months or hours that are mutually agreeable.
5. Delivery Term: TBD

III. Evaluation Criteria

PG&E will evaluate Bids using the evaluation criteria outlined below. PG&E will evaluate Bids for each delivery year independently, which may result in the selection of Bids for non-consecutive delivery years from one Bidder.

A. Quantitative Evaluation

PG&E plans to evaluate Bids based on a portfolio approach with the objective of maximizing revenue from the bids received.

B. Qualitative Evaluation

For the Solicitation, PG&E may apply a qualitative adjustment factor for counterparties that have acceptable credit with PG&E and minimize proposed edits to the form of Agreement.

1. Credit

PG&E may consider the Participant's capability to perform all of its financial and financing obligations under the Agreement and PG&E's overall credit concentration with the Participant or its banks, including any of Participant's affiliates.

2. Agreement Modifications

PG&E may assess the materiality and cost impact of any of Participant's proposed modifications to the Agreement. PG&E has a preference for standardized Agreements. To the extent possible, PG&E requests Bidders limit edits to the Agreement to the following sections:

- Product (in limited circumstances)
- Quantity
- Green Attributes Price
- Energy Delivery Period
- Delivery Point
- Credit Terms

3. Other Qualitative Considerations

In addition to the criteria specifically listed above, PG&E may consider other qualitative factors that could impact the value of Bids, including, but not limited to: previous adverse commercial experience between PG&E and Participant; Participant concentration; and existence of an acceptable EEI Master Agreement between PG&E and Participant.

IV. Required Information

A. Submission Overview

All Bid submittal information pertaining to this Solicitation will be hosted on the Power Advocate site. Telephonic, hardcopy or facsimile transmission of a Bid is not acceptable. In order to participate in this Solicitation, Bidders must register and be accepted through Power Advocate at the Public Registration Link:

[TBD]

PG&E strongly encourages Bidders to register with Power Advocate well before Bids are due. Detailed instructions for submitting Bid(s) and using Power Advocate are on PG&E's Solicitation website.

Electronic Documents: The electronic documents for the attachments must be in a Microsoft Word, Excel file or Adobe Acrobat PDF file as applicable. For each document, please include the Bidder's company name in each file name.

B. Required Forms

1. Bid Package

The following documents, which are on the PG&E's Solicitation website, must be completed and included with each Bid(s):

a. Bid Form (Attachment A)

   i. Bidder must provide all applicable information requested in the form, and all inputs must match the respective information provided in other required documentation.
   ii. PG&E will only accept one Bid per counterparty per delivery term. Brokers submitting on behalf of multiple counterparties may do so, but must designate the name of counterparty in the Bid Form.
   iii. PG&E will not accept Bids that are contingent on the selection of another bid;

b. Redline of Agreement (Attachment B);

c. Signed Non-Disclosure Agreement (Attachment C);

d. Documentation of Entity Legal Status from the California Secretary of State; and

e. Bidder or end-user counterparty must demonstrate that it has an "Active" legal status authorized by the California Secretary of State in order to engage in business with PG&E. A webpage screenshot verifying Bidder or end-user counterparty's "Active" legal status via the California Secretary of State's webpage is acceptable. The California Secretary of State website is located at https://businesssearch.sos.ca.gov/.

V. Confidentiality

No Bidder shall collaborate on or discuss with any other Bidder or potential Bidding strategies, the substance of any Bid(s), including without limitation the price or any other terms or conditions of any Bid(s), or whether PG&E has Selected Bids or not.

All information and documents in Bidder's Package that have been clearly identified and marked by Bidder as "Proprietary and Confidential" on each page on which confidential information appears shall be considered confidential information. PG&E shall not disclose such confidential information and documents to any third parties except for PG&E's employees, agents, counsel, accountants, advisors, or contractors who have a need to know such information and have agreed to keep such information confidential and except as provided otherwise in this section. In addition, Bidder's Package will be disclosed to the IE.

Notwithstanding the foregoing, it is expressly contemplated that the information and documents submitted by Bidder in connection with this Solicitation, including Bidder's confidential information, may be provided to the CPUC, its staff, and the Procurement Review Group ("PRG"), and established pursuant to D.02-08-071. PG&E retains the right to disclose any information or documents provided by Bidder to the CPUC, the PRG, in the advice letter filing or in order to comply with any applicable law, regulation, or any exchange, control area or California Independent System Operator rule, or order issued by a court or entity with competent jurisdiction over PG&E at any time even in the absence of a protective order, confidentiality agreement, or nondisclosure agreement, as the case may be, without notification to Bidder and without liability or any responsibility of PG&E to Bidder. PG&E cannot ensure that the CPUC will afford confidential treatment to Bidder's confidential information, or that confidentiality agreement or orders will be obtained from and/or honored by the PRG, the California Energy Commission, or the CPUC. By submitting a Bid, Bidder agrees to adhere and be bound by the confidentiality provisions described in this section.

The treatment of confidential information described above shall continue to apply to information related to Selected Bids.

VI. Procurement Review Group Review

Following completion of the evaluation and ranking of Bids, PG&E will submit the results of the evaluation and its recommendations to its PRG members. PG&E will consider any alternative recommendations proposed by the PRG. PG&E, in its sole discretion, shall determine whether any alternatives proposed by the PRG should be adopted. PG&E has no obligation to obtain the concurrence of the PRG with respect to any Bids.

PG&E assumes no responsibility for the actions of the PRG, including actions that may delay or otherwise affect the schedule for this Solicitation, including the timing of the selection of Bids and the obtaining of Regulatory Approval.

VII. Regulatory Approval

After Agreement execution, PG&E is required to submit executed Agreements to the CPUC for approval via an advice letter filing.

The effectiveness of any executed Agreement is expressly conditioned on PG&E's receipt of final and non-appealable CPUC approval of such Agreement ("Regulatory Approval").

VIII. Dispute Resolution

Except as expressly set forth in this Solicitation Protocol, by submitting a Bid, Bidder knowingly and voluntarily waives all remedies or damages at law or equity concerning or related in any way to the Solicitation, the Solicitation Protocol and/or any attachments to the Solicitation Protocol ("Waived Claims"). The assertion of any Waived Claims by Bidder may, to the extent that Bidder's Package has not already been disqualified, automatically disqualify such Bid from further consideration in the Solicitation.

By submitting a Bid, Bidder agrees that the only forums in which Bidder may assert any challenge with respect to the conduct or results of the Solicitation is through the Alternative Dispute Resolution ("ADR") services provided by the CPUC pursuant to Resolution ALJ-185, August 25, 2005. The ADR process is voluntary in nature, and does not include processes, such as binding arbitration, that impose a solution on the disputing parties. PG&E will consider the use of ADR under the appropriate circumstances. Additional information about this program is available on the CPUC's website at the following link: www.cpuc.ca.gov/PUBLISHED/Agenda_resolution/47777.htm.

Participant further agrees that other than through the ADR process, the only means of challenging the conduct or results of the Solicitation is a protest to an Advice Letter Filing seeking approval of one or more Agreements entered into as a result of the Solicitation, that the sole basis for any such protest shall be that PG&E allegedly failed in a material respect to conduct the Solicitation in accordance with this Solicitation Protocol, and the exclusive remedy available to Bidder in the case of such a protest shall be an order of the CPUC that PG&E again conduct any portion of the Solicitation that the CPUC determines was not previously conducted in accordance with the Solicitation Protocol. Bidder expressly waives any and all other remedies, including, without limitation, compensatory and/or exemplary damages, restitution, injunctive relief, interest, costs, and/or attorney's fees. Unless PG&E elects to do otherwise in its sole discretion during the pendency of such a protest or ADR process, the Solicitation and any related regulatory proceedings related to the Solicitation, will continue as if the protest had not been filed, unless the CPUC has issued an order suspending the Solicitation or PG&E has elected to terminate the Solicitation.

Bidder agrees to indemnify and hold PG&E harmless from any and all claims by any other Bidder asserted in response to the assertion of a Waived Claim by Bidder or as a result of a Bidder's protest to an advice letter filing with the CPUC resulting from the Solicitation.

Except as expressly provided in this Solicitation Protocol, nothing herein including Bidder's waiver of the Waived Claims as set forth above, shall in any way limit or otherwise affect the rights and remedies of PG&E. Nothing in this Solicitation Protocol is intended to prevent any Bidder from informally communicating with the CPUC or its staff regarding this solicitation.

IX. Termination of the Solicitation-Related Matters

PG&E reserves the right at any time, in its sole discretion, to terminate the Solicitation for any reason without prior notification to Bidders and without liability to, or responsibility of, PG&E or anyone acting on PG&E's behalf. Without limitation, grounds for termination of the Solicitation may include the assertion of any Waived Claims by a Bidder or a determination by PG&E that, following evaluation of the Bids, there are no Bids that meet the requirements of this Solicitation.

PG&E reserves the right to terminate further participation in this process by any Bidder, to accept any Bid or to enter into any Agreement, and to reject any or all Bids, all without notice and without assigning any reasons and without liability to PG&E or anyone acting on PG&E's behalf. PG&E shall have no obligation to consider any Bids.

In the event of termination of the Solicitation for any reason, PG&E will not reimburse Bidder for any expenses incurred in connection with the Solicitation. PG&E shall have no obligation to reimburse any Bidder's expenses regardless of whether such Bidder's Package is selected, not selected, rejected or disqualified. Unless earlier terminated, the Solicitation will terminate automatically upon the execution of one or more Agreements by Participants with Selected Bids. In the event that no Agreements are executed, then the solicitation will terminate automatically on ***[PG&E to insert date]***.

X. Bidder's Representations and Warranties

1. By submitting a Bid and clicking "Yes" to the "Acknowledgment of Protocol" section of the Bid Form, Bidder agrees to be bound by the conditions of the Solicitation, and makes the following representations, warranties, and covenants to PG&E, which representations, warranties, and covenants shall be deemed to be incorporated in their entireties into each of Bidder's Package. Bidder agrees that an electronic signature of a duly authorized representative of Bidder shall be the same as delivery of an executed original document for purposes of the Bid Form.

    - Bidder has read, understands and agrees to be bound by all terms, conditions and other provisions of this Solicitation Protocol;
    - Bidder has had the opportunity to seek independent legal and financial advice of its own choosing with respect to the Solicitation and this Solicitation Protocol, including the submittal forms and documents listed in this Solicitation Protocol which are posted on the RFO website;
    - Bidder has obtained all necessary authorizations, approvals and waivers, if any, required by Bidder to submit its Bid pursuant to the terms of this Solicitation Protocol and to enter into an Agreement with PG&E;
    - Bidder's Package complies with all applicable laws;

- Bidder has not engaged, and covenants that it will not engage, in any communications with any other actual or potential Bidder in the Solicitation concerning this Solicitation, price terms in Bidder's Package, or related matters and has not engaged in collusion or other unlawful or unfair business practices in connection with the Solicitation;
- Any Bid submitted by Bidder is subject only to PG&E's acceptance, in PG&E's sole discretion; and
- The information submitted by Bidder to PG&E in connection with the Solicitation and all information submitted as part of any Bid is true and accurate as of the date of Bidder's submission. Bidder also covenants that it will promptly update such information with PG&E upon any material change thereto.

2. By submitting a Bid, Bidder acknowledges and agrees:

   - That PG&E may rely on any or all of Bidder's representations, warranties, and covenants in the Solicitation (including any Bid submitted by Bidder); and
   - That in PG&E's evaluation of Bids pursuant to the Solicitation, PG&E has the right to disqualify a Bidder that is unwilling or unable to meet any other requirement of the Solicitation, as determined by PG&E in its sole discretion.

3. BY SUBMITTING A BID, BIDDER HEREBY ACKNOWLEDGES AND AGREES THAT ANY BREACH BY BIDDER OF ANY OF THE REPRESENTATIONS, WARRANTIES AND COVENANTS IN THESE SOLICITATION INSTRUCTIONS SHALL CONSTITUTE GROUNDS FOR IMMEDIATE DISQUALIFICATION OF SUCH BIDDER, IN ADDITION TO ANY OTHER REMEDIES THAT MAY BE AVAILABLE TO PG&E UNDER APPLICABLE LAW, AND DEPENDING ON THE NATURE OF THE BREACH, MAY ALSO BE GROUNDS FOR TERMINATING THE SOLICITATION IN ITS ENTIRETY.

APPENDIX F.2

2019 Bundled RPS Energy Sale Solicitation
Bid Form

March 15, 2019

Pacific Gas and Electric Company

2019 Bundled RPS Energy Sale Solicitation Bid Form

Contact Information	
Bidder Name:	
Bidder Type:	
Email:	
Phone:	
Street:	
City:	
State:	
Zip:	
Buyer/Counterparty:	
Buyer/Counterparty Type:	
Email:	
Phone:	
Street:	
City:	
State:	
Zip:	

Product & Bid Information	
Product:	
Delivery Location:	
Payment Index:	
Schedule or delivery requirements:	
Premium (+)/Discount (-) to Payment Index ($/MWh)	

Delivery Year	Bid Quantity
TBD	
TBD	
TBD	
TBD	
TBD	

Acknowledgement of Protocol	
By selecting "Yes" Participant hereby agrees to the terms of the Solicitation Protocol. Participant acknowledges that any costs incurred to become eligible or remain eligible for the solicitation, and any costs incurred to prepare a bid for this solicitation are solely the responsibility of Participant.	
Title:	
Electronic Signature:	
Select "Yes" to certify that the typed name acts as your electronic signature.	

Participant Authorization	
By selecting "Yes" Participant hereby confirms that they are "a duly authorized representative of Participant."	
Title:	
Electronic Signature:	
Select "Yes" to certify that the typed name acts as your electronic signature.	

Attestation	
By providing the electronic signature below Participant hereby attests that all information provided in this Bid Package and in response to this REC Solicitation is true and correct to the best of Participant's knowledge as of the date such information is provided.	
Title:	
Electronic Signature:	
Select "Yes" to certify that the typed name acts as your electronic signature.	

APPENDIX F.3

EEI Master Power Purchase and Sale Agreement Short Term Sales Confirmation Between Pacific Gas and Electric Company

March 15, 2019

EEI MASTER POWER PURCHASE AND SALE AGREEMENT
SHORT TERM SALES CONFIRMATION
BETWEEN
PACIFIC GAS AND ELECTRIC COMPANY
AND
[**Buyer to insert its full name here in all caps**]

This confirmation ("Confirmation") confirms the transaction ("Transaction") between Pacific Gas and Electric Company, a California corporation, but limited for all purposes hereunder to its electric procurement and electric fuels functions ("Seller" or "Party B"), and [____________________________] [***Buyer to insert its full name, place of formation and type of entity***] ("Buyer" or "Party A"), each individually a "Party" and together the "Parties", effective as of the Execution Date, for the sale and purchase of the Product defined herein.

Except as otherwise expressly stated herein, this Confirmation is subject to, and incorporates by reference with the same force and effect as if set forth herein, all of the terms and provisions of the Parties' EEI Master Power Purchase and Sale Agreement, together with the Cover Sheet [and the amendments and annexes thereto] [***PG&E to identify any amendments or annexes here]***, dated as of [***MM/DD/YYYY***] [***PG&E to insert date in MM/DD/YYYY format***] (collectively, ["Master Agreement"] ["EEI Agreement" ***if no Collateral Annex***]) [, and the corresponding Collateral Annex and Paragraph 10 to the Collateral Annex thereto]. [Such Collateral Annex and Paragraph 10 to the Collateral Annex shall be referred to collectively herein as the "Collateral Annex"]. [The Master Agreement and the Collateral Annex shall be referred to collectively herein as the "EEI Agreement".] The EEI Agreement and this Confirmation shall be referred to collectively herein as the "Agreement."

Capitalized terms used but not defined in this Confirmation shall have the meanings ascribed to them in the EEI Agreement, the RPS (defined herein), or the Tariff (defined herein). If there is a conflict between the terms in this Confirmation and those in the EEI Agreement, this Confirmation shall control.

[PG&E to delete references to the Collateral Annex above if there is no existing Collateral Annex between the Parties]

[Standard contract terms and conditions shown in shaded text are those that "may not be modified" per CPUC Decisions ("D.") 07-11-025; D.10-03-021, as modified by D.11-01-025; and D.13-11-024.]

Seller: Pacific Gas and Electric Company		**Buyer: [*Buyer to insert its name here*]**
Contact Information:	**Name:** Pacific Gas and Electric Company ("Seller" or "Party B")	**Name: [*Buyer to insert its contact name here*]** ("Buyer" or "Party A")
	All Notices: P.O. Box 770000, Mail Code N12E San Francisco, CA 94177 Attn: Senior Manager, Contract Management Phone: (415) 973-8660 E-mail: [***PG&E to insert here***]	**All Notices:** [***Buyer to insert its address for Notices here***] Attn: [***Buyer to insert here***] Phone: [***Buyer to insert here***] Email: [***Buyer to insert here***]

	Invoices: Attn: Manager, Contract Settlements Phone: (415) 973-4277 Email:	**Invoices:** Attn: [***Buyer to insert here***] Phone: [***Buyer to insert here***] Email: [***Buyer to insert here***]
	Scheduling: Attn: Day-Ahead Scheduling Phone: (415) 973-6222 Email:	**Scheduling:** Attn: [***Buyer to insert here***] Phone: [***Buyer to insert here***] Email: [***Buyer to insert here***]
	Payments: Attn: Manager, Contract Settlements Phone: (415) 973-4277 Email:	**Payments:** Attn: [***Buyer to insert here***] Phone: [***Buyer to insert here***] Email: [***Buyer to insert here***]
	Wire Transfer: BNK: ABA: ACCT: Duns: Federal Tax ID Number:	**Wire Transfer:** BNK: ABA: ACCT: Duns: Federal Tax ID Number:
	Credit and Collections: **Credit and Collections:** Attn: Manager, Credit Risk Management Phone: (415) 972-5188 Email: PGERiskCredit@pge.com **Defaults:** With additional Notices of an Event of Default or Potential Event of Default to: Pacific Gas and Electric Company 77 Beale Street, Mail Code B30A San Francisco, CA 94105 Attn: Legal Department Email: [***PG&E to insert here***]	**Credit and Collections:** **Credit and Collections:** Attn: [***Buyer to insert here***] Phone: [***Buyer to insert here***] Email: [***Buyer to insert here***] **Collateral:** Attn: [***Buyer to insert here***] Phone: [***Buyer to insert here***] E-mail: [***Buyer to insert here***] **Defaults:** With additional Notices of an Event of Default or Potential Event of Default to: Address: [***Buyer to insert here***] Attn: [***Buyer to insert here***] Email: [***Buyer to insert here***]

ARTICLE 1
COMMERCIAL TERMS

<table>
<tr><td colspan="2">Seller: PACIFIC GAS AND ELECTRIC COMPANY</td><td>Buyer: [Buyer to insert its full name here in all caps]</td></tr>
<tr><td>Product:</td><td colspan="2">The Product shall consist of Electric Energy and associated Green Attributes from the Project, as further described and subject to the provisions herein.</td></tr>
<tr><td>Project:</td><td colspan="2">All Product sold hereunder shall be generated by the facility or facilities (“Project”) listed in Appendix A to this Confirmation or identified pursuant to Section 8.2 herein.

Seller shall have sole discretion throughout the Term to designate and re-designate, as applicable, the Project by selecting one or more of the facilities from Appendix A or pursuant to Section 8.2 herein.

Buyer shall not be entitled to, and shall not receive, any amount of Green Attributes produced by the Project that is in excess of the Total Quantity.

Buyer shall not be entitled to, and shall not receive, any amount of Electric Energy produced by the Project that is in excess of the Energy Quantity.</td></tr>
<tr><td>Quantity:</td><td colspan="2">(a) <u>For Green Attributes</u>: “Total Quantity”, with respect to an applicable year, shall be equal to those volumes of Green Attributes specified for that applicable year in the Delivery Term Quantity Schedule set forth below and shall be conveyed during the Green Attributes Delivery Period to Buyer as provided herein and subject to the limitation specified below with respect to each Calculation Period.

(b) <u>For Electric Energy</u>: “Energy Quantity”, with respect to an applicable year, shall be equal to those volumes of Electric Energy specified for that applicable year in the Delivery Term Quantity Schedule set forth below and shall be delivered during the Energy Delivery Period to Buyer as provided herein and subject to the limitation specified below with respect to each Calculation Period.
<table>
<tr><td colspan="3">Delivery Term Quantity Schedule</td></tr>
<tr><td>Year</td><td>Green Attributes (MWh)</td><td>Electric Energy (MWh)</td></tr>
<tr><td>[Buyer to insert]</td><td>[Buyer to insert]</td><td>[Buyer to insert]</td></tr>
</table></td></tr>
<tr><td>Energy Price:</td><td colspan="2">The Energy Price shall mean the Index Price for each MWh of Delivered Energy delivered to Buyer under this Agreement.</td></tr>
<tr><td>Green Attributes Price:</td><td colspan="2">The Green Attributes Price shall mean, with respect to an applicable year, that price in dollars for each MWh of Green Attributes conveyed to Buyer under this Agreement, as specified in the table below.
<table>
<tr><td>Year</td><td>Green Attributes Price ($)</td></tr>
<tr><td>[Buyer to insert]</td><td>[Buyer to insert]</td></tr>
</table></td></tr>
<tr><td>Term of Transaction:</td><td colspan="2">Except as otherwise provided herein, the term of the Transaction shall commence upon the Execution Date and shall continue until the end of the Delivery Term and the satisfaction of all other obligations of the Parties under this Agreement (“Term”).</td></tr>
</table>

	This Confirmation, and the Transaction and Term hereunder, shall terminate early in the event of a failure to satisfy the Green Attributes Condition Precedent defined below or as otherwise provided in the Agreement. Termination because of a failure to satisfy the Green Attributes Condition Precedent shall terminate all of the Parties' obligations under the Confirmation as of the Transaction Termination Date as provided in Section 4.2, except for the Parties' confidentiality obligations under Article 9 herein.
Credit Requirements:	(a) This Confirmation's credit requirements for the Electric Energy portion of the Product shall be governed by the EEI Agreement. (b) This Confirmation's credit requirements for the Green Attributes portion of the Product shall apply as specified below: (i) If the EEI Agreement has a Collateral Annex, then the Exposure Amount for the Green Attributes portion of the Product shall be equal to the product of the following: (I) fifteen percent (15%), multiplied by (II) the volume of the undelivered Green Attributes, multiplied by (III) the Green Attributes Price. (ii) In the event the EEI Agreement does *not* have a Collateral Annex *and* Section 8.2(c), entitled "Collateral Threshold" with respect to "Party B Credit Protection", of the EEI Agreement applies, then the Termination Payment for the Green Attributes portion of the Product to be delivered to Party B as described in Section 8.2(c) of the EEI Agreement shall be equal to the product of the following: (I) fifteen percent (15%), multiplied by (II) the volume of the undelivered Green Attributes, multiplied by (III) the Green Attributes Price. (c) Section 8.1 of the EEI Agreement, entitled "Party A Credit Protection", and all corresponding provisions of (i) the Cover Sheet to Section 8.1 of the EEI Agreement and (ii) the Collateral Annex with respect to such Section 8.1 and the applicable provisions thereto of Paragraph 10 to the Collateral Annex do not apply to this Confirmation.
Delivery Term:	The "Delivery Term" shall consist of both the Energy Delivery Period and the Green Attributes Delivery Period.
Energy Delivery Period:	Subject to the satisfaction, or waiver in writing by both Parties, of the Green Attributes Condition Precedent, the "Energy Delivery Period" shall (1) commence as of the later of [***MM/DD/YYYY***] [***Buyer to insert date in MM/DD/YYYY format***] and that date upon which CPUC Approval occurs, and (2) end on the earlier of the conclusion of hour ending 2400 (PPT) on [***MM/DD/YYYY***] [***Buyer to insert date in MM/DD/YYYY format for short-term transaction***] and that date upon which the amount of Electric Energy delivered by Seller satisfies the Energy Quantity.
Green Attributes Delivery Period:	Subject to the satisfaction, or waiver in writing by both Parties, of the Green Attributes Condition Precedent, the "Green Attributes Delivery Period" shall commence on the first day that Seller conveys Green Attributes to Buyer and shall end on that date upon which the amount of Green Attributes conveyed to Buyer satisfies the Total Quantity. Seller shall convey Green Attributes to Buyer in the form of WREGIS Certificates. Seller shall transfer WREGIS Certificates into Buyer's WREGIS account in an amount required to satisfy the Total Quantity.

Delivery Point:	The "Delivery Point" where Buyer shall take possession of the Electric Energy shall be [NP15 / SP15 / ZP26]. [***Buyer to designate***]
Scheduling Obligations:	Seller, or a qualified third party designated by Seller, shall act as Scheduling Coordinator for the Project. Buyer hereby authorizes Seller, or its third-party Scheduling Coordinator designee, to deliver the Electric Energy to the CAISO at the Delivery Point as an agent on Buyer's behalf.
Condition Precedent to the Green Attributes Obligations:	Notwithstanding any other provision of this Confirmation to the contrary, all of the Parties' obligations except for the Parties' confidentiality obligations under Article 9 herein, are conditioned upon [(a)] PG&E's receipt, or the Parties' written waiver, of CPUC Approval as defined below [; and (b) PG&E's receipt of the Performance Assurance from Buyer no later than five (5) Business Days following PG&E's Notice of CPUC Approval (defined below)] ([collectively,]"Green Attributes Condition Precedent").

ARTICLE 2
DEFINITIONS

2.1 "Balancing Authority" has the meaning set forth in the CAISO Tariff.

2.2 "Balancing Authority Area" has the meaning set forth in the CAISO Tariff.

2.3 "Broker or Index Quotes" means quotations solicited or obtained in good faith from (a) regularly published and widely-distributed daily forward price assessments from a broker that is not an Affiliate of either Party and who is actively participating in markets for the relevant Products or (b) end-of-day prices for the relevant Products published by exchanges which transact in the relevant markets.

2.4 "Business Day" means all calendar days other than those days on which the Federal Reserve member banks in New York City are authorized or required by law to be closed, and shall be between the hours of 8:00 a.m. and 5:00 p.m. Pacific Prevailing Time for the relevant Party's principal place of business where the relevant Party, in each instance unless otherwise specified, shall be the Party from whom the Notice, payment or delivery is being sent and by whom the Notice or payment or delivery is to be received.

2.5 "CAISO" means the California Independent System Operator Corporation or any successor entity performing similar functions.

2.6 "CAISO Grid" has the same meaning as "CAISO Controlled Grid" as defined in the CAISO Tariff.

2.7 "California Renewables Portfolio Standard" or "RPS" means the renewable energy program and policies established by California State Senate Bills 1078, X1 - 2 and 350, codified in California Public Utilities Code Sections 399.11 through 399.32 and California Public Resources Code Sections 25740 through 25751, as such provisions are amended or supplemented from time to time.

2.8 "CARB" means the California Air Resources Board or its successor agency.

2.9 "CEC" means the California Energy Commission or its successor agency.

2.10 “Contract Price” means the Energy Price plus the Green Attributes Price.

2.11 “CPUC” means the California Public Utilities Commission or its successor entity.

2.12 “CPUC Approval” means a final and non-appealable order of the CPUC, without conditions or modifications unacceptable to the Parties, or either of them, which contains the following terms:

(a) approves this Agreement in its entirety, including payments to be made by the Buyer, subject to CPUC review of the Buyer's administration of the Agreement; and

(b) finds that any procurement pursuant to this Agreement is procurement from an eligible renewable energy resource for purposes of determining Buyer's compliance with any obligation that it may have to procure eligible renewable energy resources pursuant to the California Renewables Portfolio Standard (Public Utilities Code Section 399.11 *et seq.*), Decision 03-06-071, or other applicable law.

CPUC Approval will be deemed to have occurred on the date that a CPUC decision containing such findings becomes final and non-appealable.

For the purpose of this Section 2.12, a CPUC Energy Division disposition which contains such findings, or deems approved an advice letter requesting such findings, shall be deemed to satisfy the CPUC decision requirement set forth above.

Also, for the purpose of this Section 2.12 only, the references therein to “Buyer” shall mean “Seller”.

2.13 “Credit Rating” means, with respect to any entity, (a) the rating then assigned to such entity’s unsecured, senior long-term debt obligations (not supported by third party credit enhancements), or (b) if such entity does not have a rating for its unsecured, senior long-term debt obligations, then the rating assigned to such entity as an issuer rating by S&P and/or Moody’s. If the entity is rated by both S&P and Moody’s and such ratings are not equivalent, the lower of the two ratings shall determine the Credit Rating. If the entity is rated by either S&P or Moody’s, but not both, then the available rating shall determine the Credit Rating.

2.14 “Delivered Energy” means the Electric Energy from the Project that is delivered by Seller to Buyer at the Delivery Point.

2.15 “Electric Energy” means three-phase, 60-cycle alternating current electric energy measured in MWh and net of auxiliary loads and station electrical uses (unless otherwise specified).

2.16 “Eligible Renewable Energy Resource” or “ERR” has the meaning set forth in California Public Utilities Code Section 399.12 and California Public Resources Code Section 25741, as either code provision is amended or supplemented from time to time.

2.17 “Execution Date” means the latest signature date found on the signature page of this Agreement.

2.18 “Force Majeure” means an event or circumstance which prevents one Party from performing its obligations under this Agreement, which event or circumstance was not anticipated as of the Execution Date, which is not within the reasonable control of, or the result of the negligence of, the

Claiming Party, and which, by the exercise of due diligence, the Claiming Party is unable to overcome or avoid or cause to be avoided. Force Majeure shall not be based on (a) the loss of Buyer's markets; (b) Buyer's inability economically to use or resell the Product purchased hereunder; (c) the loss or failure of Seller's supply unless caused by a force majeure event at the Project; or (d) Seller's ability to sell the Product at a price greater than the Contract Price. Neither Party may raise a claim of Force Majeure based in whole or in part on curtailment by a Transmission Provider unless (i) such Party has contracted for firm transmission with a Transmission Provider for the Product to be delivered to or received at the Delivery Point and (ii) such curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the Transmission Provider's tariff; provided, however, that existence of the two foregoing factors shall not be sufficient to conclusively or presumptively prove the existence of a Force Majeure absent a showing of other facts and circumstances which in the aggregate with such factors establish that a Force Majeure as defined in the first sentence hereof has occurred.

2.19 "Governmental Authority" means any federal, state, local or municipal government, governmental department, commission, board, bureau, agency, or instrumentality, or any judicial, regulatory or administrative body, having jurisdiction as to the matter in question.

2.20 "Green Attributes" means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Project, and its avoided emission of pollutants. Green Attributes include but are not limited to Renewable Energy Credits, as well as: (a) any avoided emission of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (b) any avoided emissions of carbon dioxide (CO2), methane (CH4), nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change, or otherwise by Law, to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere[1]; (c) the reporting rights to these avoided emissions, such as Green Tag Reporting Rights. Green Tag Reporting Rights are the right of a Green Tag Purchaser to report the ownership of accumulated Green Tags in compliance with federal or state Law, if applicable, and to a federal or state agency or any other party at the Green Tag Purchaser's discretion, and include without limitation those Green Tag Reporting Rights accruing under Section 1605(b) of The Energy Policy Act of 1992 and any present or future federal, state, or local Law, regulation or bill, and international or foreign emissions trading program. Green Tags are accumulated on a MWh basis and one Green Tag represents the Green Attributes associated with one (1) MWh of Electric Energy. Green Attributes do not include (i) any Electric Energy, capacity, reliability or other power attributes from the Project, (ii) production tax credits associated with the construction or operation of the Project and other financial incentives in the form of credits, reductions, or allowances associated with the Project that are applicable to a state or federal income taxation obligation, (iii) fuel-related subsidies or "tipping fees" that may be paid to Seller to accept certain fuels, or local subsidies received by the generator for the destruction of particular preexisting pollutants or the promotion of local environmental benefits, or (iv) emission reduction credits encumbered or used by the Project for compliance with local, state, or federal operating and/or air quality permits. If the Project is a biomass or biogas facility and Seller receives any tradable Green Attributes based on the greenhouse gas reduction benefits or other emission offsets attributed to its fuel usage, it shall provide Buyer with sufficient Green Attributes to ensure that there are zero net emissions associated with the production of electricity from the Project.

2.21 "Index Price" means the Trading Hub price (as defined in the CAISO Tariff) associated with the Delivered Energy to the Delivery Point for each applicable hour as published by the CAISO on

[1] Avoided emissions may or may not have any value for GHG compliance purposes. Although avoided emissions are included in the list of Green Attributes, this inclusion does not create any right to use those avoided emissions to comply with any GHG regulatory program.

the CAISO website or any successor thereto, unless a substitute publication and/or index is mutually agreed to by the Parties.

2.22 "Law" means any statute, law, treaty, rule, regulation, CEC guidance document, ordinance, code, permit, enactment, injunction, order, writ, decision, authorization, judgment, decree or other legal or regulatory determination or restriction by a court or Governmental Authority of competent jurisdiction, including any of the foregoing that are enacted, amended, or issued after the Execution Date, and which becomes effective after the Execution Date; or any binding interpretation of the foregoing. For the purposes of the definition of "CPUC Approval" in Section 2.12 and Sections 6.1(a), 6.1(b) and 8.3(b) in this Confirmation, the term "law" shall have the meaning set forth in this definition.

2.23 "Letter of Credit" means an irrevocable, non-transferable, standby letter of credit the form of which shall be substantially as contained in Appendix B to this Agreement; provided that, if the issuer is a U.S. branch of a foreign commercial bank, the intended beneficiary may require changes to such form; and the issuer must be a Qualified Institution on the date of delivery of the Letter of Credit to the Secured Party. In case of a conflict of this definition with any other definition of "Letter of Credit" contained in the EEI Agreement or any exhibit or annex thereto, this definition shall supersede any such other definition for purposes of the Transaction to which this Agreement applies.

2.24 "Market Quotation Average Price" means the arithmetic mean of the quotations solicited in good faith from not less than three (3) Reference Market-Makers (as hereinafter defined); provided, however, that the Party obtaining the quotes shall use reasonable efforts to obtain good faith quotations from at least five (5) Reference Market-Makers and, if at least five (5) such quotations are obtained, the Market Quotation Average Price shall be determined by disregarding the highest and lowest quotations and taking the arithmetic mean of the remaining quotations. The quotations shall be based on the offers to sell or bids to buy, as applicable, obtained for transactions substantially similar to each Terminated Transaction. The quote must be obtained assuming that the Party obtaining the quote will provide sufficient credit support for the proposed transaction. Each quotation shall be obtained, to the extent reasonably practicable, as of the same day and time (without regard to different time zones) on or as soon as reasonably practicable after the relevant Early Termination Date. The day and time as of which those quotations are to be obtained will be selected in good faith by the Party obtaining the quotations and in accordance with the Notice provided pursuant to Section 5.2 of the EEI Agreement, which designates the Early Termination Date. If fewer than three quotations are obtained, it will be deemed that the Market Quotations Average Price in respect of such Terminated Transaction or group of Terminated Transactions cannot be determined. For purposes of this Section 2.24, "Reference Market-Maker" means a leading dealer in the relevant market selected by a Party determining its exposure in good faith from among dealers of the highest credit standing which satisfy all the criteria that such Party applies generally at the time in deciding whether to offer or to make an extension of credit.

2.25 "Notice" means written communications by a Party to be delivered by hand delivery, United States mail, overnight courier service, or electronic messaging (e-mail). The contacts table of this Confirmation contains the names and addresses to be used for Notices.

2.26 "Qualified Institution" means either a U.S. commercial bank, or a U.S. branch of a foreign bank acceptable to the Beneficiary Party in its sole discretion; and in each case such bank must (i) have a Credit Rating of at least: (a) "A-, with a stable designation" from S&P and "A3, with a stable designation" from Moody's, if such bank is rated by both S&P and Moody's; or (b) "A-, with a stable designation" from S&P or "A3, with a stable designation" from Moody's, if such bank is rated by either S&P or Moody's, but not both, even if such bank was rated by both S&P and Moody's as of the date of issuance of the Letter of Credit but ceases to be rated by either, but not both of those ratings agencies, and (ii) have assets of at least $10 billion US Dollars.

2.27 "Real-Time Market" has the meaning set forth in the Tariff and shall include any market that CAISO may establish prior to or during the Term that clears at an interval between the Day-Ahead Market and the Real-Time Market.

2.28 "Renewable Energy Credit" or "REC" has the meaning set forth in California Public Utilities Code Section 399.12(h) and CPUC Decision 08-08-028, as may be amended from time to time or as further defined or supplemented by Law.

2.29 "Replacement Price" means the price at which Buyer, acting in a commercially reasonable manner, purchases for delivery at the Delivery Point a replacement for any Product specified in a Transaction but not delivered by Seller, plus (a) costs reasonably incurred by Buyer in purchasing such substitute Product and (b) additional transmission charges, if any, reasonably incurred by Buyer to the Delivery Point, or absent a purchase, the market price at the Delivery Point for such Product not delivered as determined by Buyer in a commercially reasonable manner; provided, however, in no event shall such price include any penalties, ratcheted demand or similar charges, nor shall Buyer be required to utilize or change its utilization of its owned or controlled assets or market positions to minimize Seller's liability. For the purposes of this definition, Buyer shall be considered to have purchased replacement Product to the extent Buyer shall have entered into one or more arrangements in a commercially reasonable manner whereby Buyer repurchases its obligation to sell and deliver the Product to another party at the Delivery Point.

2.30 "Sales Price" means the price at which Seller, acting in a commercially reasonable manner, resells any Product not received by Buyer, deducting from such proceeds any (a) costs reasonably incurred by Seller in reselling such Product and (b) additional transmission charges, if any, reasonably incurred by Seller in delivering such Product to the third party purchasers, or absent a sale, the market price at the Delivery Point for such Product not received as determined by Seller in a commercially reasonable manner; provided, further, that in no event shall such price include any penalties, ratcheted demand or similar charges, nor shall Seller be required to utilize or change its utilization of its owned or controlled assets, including contractual assets, or market positions to minimize Buyer's liability. For purposes of this definition, Seller shall be considered to have resold such Product to the extent Seller shall have entered into one or more arrangements in a commercially reasonable manner whereby Seller repurchases its obligation to purchase and receive the Product from another party at the Delivery Point.

2.31 "Tariff" means the CAISO Fifth Replacement FERC Electric Tariff and protocol provisions, including any CAISO-published procedures or business practice manuals, as they may be amended, supplemented or replaced (in whole or in part) from time to time.

2.32 "Transactions" as used in the EEI Agreement shall mean the "Transaction" as defined in the preamble above.

2.33 "WREGIS" means the Western Renewable Energy Generation Information System or any successor renewable energy tracking program.

2.34 "WREGIS Certificate" has the same meaning as "Certificate" as defined by WREGIS in the WREGIS Operating Rules and are designated as eligible for complying with the California Renewables Portfolio Standard.

2.35 "WREGIS Operating Rules" means the operating rules and requirements adopted by WREGIS.

ARTICLE 3
CONVEYANCE OF ELECTRIC ENERGY AND GREEN ATTRIBUTES

3.1 Seller's Delivery of Electric Energy.

Subject to the terms and conditions of this Agreement, beginning on the first day of the Energy Delivery Period and continuing until the last day of the Energy Delivery Period, Seller shall deliver and sell, and Buyer shall purchase and receive, the Delivered Energy.

3.2 Seller's Conveyance of Green Attributes.

(a) Green Attributes. Subject to the terms and conditions of this Agreement, beginning on the first day of the Green Attributes Delivery Period and continuing until the last day of the Green Attributes Delivery Period, Seller shall convey and sell, and Buyer shall purchase and receive, those Green Attributes associated with the Delivered Energy.

(i) Seller represents and warrants that Seller holds the rights to such Green Attributes from the Project and Seller agrees to convey such Green Attributes to Buyer as included in the delivery of the Product from the Project subject to the terms and conditions of this Agreement. ***[To the extent the Project is a biomethane facility, the Parties shall modify this section as necessary to ensure that it, and the definition of "Green Attributes", will not conflict with necessary language that will be added to address biomethane transactions, pursuant to CPUC D.13-11-024, pgs 21-24.]***

(ii) As set forth above, Seller shall convey only that amount of Green Attributes required to meet the Total Quantity and shall do so only during the Green Attributes Delivery Period.

(b) The Green Attributes in the amount of the Total Quantity shall be deemed to be conveyed to and received by Buyer under this Confirmation as set forth herein. During the Green Attributes Delivery Period, Seller shall convey to Buyer the Green Attributes associated with the Delivered Energy within the later of: (A) twenty-five (25) Business Days following the occurrence of both (I) the deposit into Seller's WREGIS account of the WREGIS Certificates for the Green Attributes for the applicable Calculation Period and (II) Buyer's payment of the Monthly Cash Settlement Amount in accordance with Article 5 herein; and (B) twenty-five (25) Business Days following the satisfaction, or written waiver by both Parties, of the Green Attributes Condition Precedent. Seller shall transfer such WREGIS Certificates in an amount equivalent to the Total Quantity to Buyer's WREGIS account such that all right, title and interest in and to the WREGIS Certificates shall transfer from Seller to Buyer.

ARTICLE 4
CPUC FILING AND APPROVAL

4.1 Filing for CPUC Approval.

Within sixty (60) days after the Execution Date, Seller shall file with the CPUC a request for CPUC Approval. Buyer shall use commercially reasonable efforts to support Seller in obtaining CPUC Approval. Seller shall have no obligation to seek rehearing or to appeal a CPUC decision which fails to approve this Confirmation or which contains findings required for CPUC Approval with conditions or modifications unacceptable to either Party. Notwithstanding anything to the contrary in the Confirmation, Seller shall not have any obligation or liability to Buyer or any third party for any action or inaction of the CPUC or other Governmental Authority affecting the approval or status of this Confirmation as a transaction eligible for portfolio content category 1, as defined in California Public Utilities Code Section 399.16(b)(1).

4.2 Termination Right and Transaction Termination Date.

In the event that: (a) the CPUC issues a final and non-appealable order not approving this Agreement in its entirety, (b) the CPUC issues a final and non-appealable order which contains conditions or modifications unacceptable to either Party, or (c) approval by the CPUC has not been received by Seller on or before sixty (60) days from the date on which Seller files for CPUC Approval, then either Party may, in its sole discretion, elect to terminate this Agreement upon Notice to the other Party provided in accordance with Article 10.7 of the EEI Agreement. Such Notice shall become effective one (1) Business Day after its provision. The effective date of the Notice shall constitute the "Transaction Termination Date". Any termination elected and noticed in accordance with this Section 4.2 shall terminate all of the Parties' rights and obligations under the Agreement as of the Transaction Termination Date, except for the Parties' confidentiality obligations under Article 9 herein.

4.3 Effect of Termination.

Any termination properly exercised by a Party under Section 4.2 shall be without liability or obligation, except for the Parties' confidentiality obligations under Article 9 herein, and shall have no effect on the status of the EEI Agreement.

ARTICLE 5
COMPENSATION

5.1 Calculation Period.

The "Calculation Period" shall be each calendar month or portion thereof that Delivered Energy was conveyed to Buyer and for which associated Green Attributes will be transferred to Buyer under this Confirmation as described in Section 3.2(b).

5.2 Monthly Cash Settlement Amount.

Buyer shall pay Seller the Monthly Cash Settlement Amount, in arrears, for each Calculation Period. The "Monthly Cash Settlement Amount" for a particular Calculation Period shall be equal to the sum of (a) plus (b) minus (c), where:

(a) equals the sum, over all hours of the Calculation Period, of the applicable Energy Price for each hour of Delivered Energy, multiplied by the quantity of Delivered Energy during that hour; and

(b) equals the Green Attributes Price multiplied by the quantity of Green Attributes (in MWhs) that will be conveyed as described in Section 3.2(b) and that are associated with the Delivered Energy in the Calculation Period; and

(c) equals the sum, over all hours of the Calculation Period, of the applicable Energy Price for each hour of Delivered Energy, multiplied by the quantity of Delivered Energy during that hour.

5.3 Payment Date.

Notwithstanding anything to the contrary in Article Six of the EEI Agreement, payment of each Monthly Cash Settlement Amount by Buyer to Seller under this Confirmation shall be due and payable four (4) calendar months following the applicable Calculation Period and on or before the later of: (a) the twentieth (20th) day of the month in which the Buyer receives from Seller an invoice for the Calculation Period to which the Monthly Cash Settlement Amount pertains, and (b) ten (10) days following the date of Buyer's receipt of an invoice issued by Seller for such applicable Calculation Period; provided that, if such payment due date is not a Business Day, then on the next Business Day. Payment to Seller shall be made by wire transfer pursuant to the Notices section of this Agreement.

5.4 Invoices.

The invoice shall include a statement detailing the amount of Delivered Energy, and associated Green Attributes, transferred to Buyer during the applicable Calculation Period. For purposes of this Confirmation, Buyer shall be deemed to have received an invoice upon Buyer's receipt by e-mail of such invoice in PDF format from Seller. Invoices to Buyer shall be sent by email to: **[*Buyer to insert*]**

ARTICLE 6
REPRESENTATIONS, WARRANTIES AND COVENANTS

6.1 Seller's Representations, Warranties, and Covenants.

(a) Seller Representations and Warranties. Seller, and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement that: (i) the Project qualifies and is certified by the CEC as an Eligible Renewable Energy Resource ("ERR") as such term is defined in Public Utilities Code Section 399.12 or Section 399.16; and (ii) the Project's output delivered to Buyer qualifies under the requirements of the California Renewables Portfolio Standard. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law.

(b) Seller and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement the Renewable Energy Credits transferred to Buyer conform to the definition and attributes required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law.

(c) Seller warrants that all necessary steps to allow the Renewable Energy Credits transferred to Buyer to be tracked in the Western Renewable Energy Generation Information System will be taken prior to the first delivery under the contract.

(i) For the avoidance of doubt, the term "contract" as used in the immediately preceding paragraph means this Confirmation.

(ii) For further clarity, the phrase "first delivery" as used in the immediately preceding paragraph means the first date of the Green Attributes Delivery Period.

(d) In addition to the foregoing, Seller warrants, represents and covenants, as of the Execution Date and throughout the Delivery Term, that:

(i) Seller has the contractual rights to sell all right, title, and interest in the Product required to be delivered hereunder;

(ii) Seller has not sold the Product required to be delivered hereunder to any other person or entity;

(iii) Seller is a "forward contract merchant" within the meaning of the United States Bankruptcy Code (as in effect as of the Execution Date of this Confirmation);

(iv) at the time of delivery, all rights, title, and interest in the Product required to be delivered hereunder are free and clear of all liens, taxes, claims, security interests, or other encumbrances of any kind whatsoever;

(v) Seller shall not substitute or purchase any Product from any generating resource other than the Project or the market for delivery hereunder; and

(vi) the facility(s) designated by Seller as the Project and all electrical output from the facility(s) designated as the Project are, or will be by the first date of the Green Attributes Delivery Period, registered with WREGIS as RPS-eligible.

(e) Seller makes no representation, warranty or covenant with respect to any portfolio content category designation pursuant to California Public Utilities Code Section 399.16 nor any eligibility of the Product to qualify as excess procurement pursuant to California Public Utilities Code Section 399.13(a)(4)(B).

(f) As of the Execution Date and throughout the Energy Delivery Period, Seller represents, warrants and covenants that the Project meets the criteria in either (A) or (B):

(A) The Project either has a first point of interconnection with a California balancing authority, or a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area; or

(B) The Project has an agreement to dynamically transfer electricity to a California balancing authority.

(g) If and to the extent that the Product sold by Seller is a resale of part or all of a contract between Seller and one or more third parties, Seller represents, warrants and covenants that the resale complies with the following conditions in (i) through (iv) below as of the Execution Date and throughout the Energy Delivery Period:

(i) The original upstream third-party contract(s) meets the criteria of California Public Utilities Code Section 399.16(b)(1)(A);

(ii) This Agreement transfers only Electric Energy and Green Attributes that have not yet been generated prior to the commencement of the Energy Delivery Period;

(iii) The Delivered Energy transferred hereunder is transferred to Buyer in real time; and

(iv) If the Project has an agreement to dynamically transfer electricity to a California balancing authority, the transactions implemented under this Agreement are not contrary to any condition imposed by a balancing authority participating in the dynamic transfer arrangement.

6.2 To the extent a change in Law occurs after the Execution Date that causes the representations, warranties, and/or covenants in Section 6.1or this Section 6.2 that continue beyond the Execution Date to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in Law.

6.3 "Commercially reasonable efforts" as set forth in this Article 6 and as applicable to Seller only shall not require Seller to incur out-of-pocket expenses in excess of twenty-five thousand dollars ($25,000.00) in the aggregate during the Term.

ARTICLE 7
TERMINATION AND CALCULATION OF TERMINATION PAYMENT

In the event this Transaction becomes a Terminated Transaction pursuant to Section 5.2 of the EEI Agreement, then the Settlement Amount with respect to this Transaction shall not be calculated in accordance with the EEI Agreement, but instead shall be calculated as follows:

The Non-Defaulting Party shall determine its Gains and Losses by determining the Market Quotation Average Price for the Terminated Transaction. In the event the Non-Defaulting Party is not able, after commercially reasonable efforts, to obtain the Market Quotation Average Price with respect to the Terminated Transaction, then the Non-Defaulting Party shall calculate its Gains and Losses for the Terminated Transaction in a commercially reasonable manner by calculating the arithmetic mean of the quotes of at least three (3) Broker or Index Quotes based on the offers to sell or bids to buy, as applicable, obtained for transactions substantially similar to the Terminated Transaction. Such Broker or Index Quotes must be obtained assuming that the Party obtaining the quote will provide sufficient credit support for the proposed transaction. In the event the Non-Defaulting Party is not able, after commercially reasonable efforts to obtain at least three (3) such Broker or Index Quotes with respect to the Terminated Transaction, then the Non-Defaulting Party shall calculate its Gains and Losses for such Terminated Transaction in a commercially reasonable manner by reference to information supplied to it by one or more third parties including, without limitation, quotations (either firm or indicative) of relevant rates, prices, yields, yield curves, volatilities, spreads or other relevant market data in the relevant markets. Third parties supplying such information may include, without limitation, dealers in the relevant markets, end-users of the relevant product, information vendors and other sources of market information; provided, however, that such third parties shall not be Affiliates of either Party. Only in the event the Non-Defaulting Party is not able, after using commercially reasonable efforts, to obtain such third-party information, then the Non-Defaulting Party shall calculate its Gains and Losses for such Terminated Transaction in a commercially reasonable manner using relevant market data it has available to it internally.

ARTICLE 8
GENERAL PROVISIONS

8.1 Buyer Audit Rights.

In addition to any audit rights provided under the EEI Agreement, Seller shall, during the Term as may be requested by Buyer, provide documentation (which may include, for example, meter data as recorded by a meter approved by the Project's governing Balancing Authority) sufficient to demonstrate that the Product has been conveyed and delivered to Buyer.

8.2 Facility Identification.

Seller shall have sole discretion throughout the Term to designate and re-designate, as applicable, the Project by selecting one or more of the facilities from Appendix A or by identifying one or more facilities as provided herein. If Seller determines that any Product to be delivered in a calendar month shall be from a facility or facilities other than those in Appendix A, then Seller shall provide Notice to Buyer identifying the facility or facilities that constitute the Project within three (3) Business Days prior to the delivery of Electric Energy from such facility or facilities in such calendar month.

8.3 Governing Law.

(a) Notwithstanding any provision to the contrary in the EEI Agreement, the Governing Law applicable to this Agreement shall be as set forth herein. This Section 8.3 does not change the Governing Law applicable to any other confirmation or transaction entered into between the Parties under the EEI Agreement.

(b) Governing Law. This agreement and the rights and duties of the parties hereunder shall be governed by and construed, enforced and performed in accordance with the laws of the state of California, without regard to principles of conflicts of law. To the extent enforceable at such time, each party waives its respective right to any jury trial with respect to any litigation arising under or in connection with this agreement.

For the purposes of Section 8.3(b) above, the words "party" and "parties" shall have the meaning ascribed to them in the preamble of this Confirmation, and the word "agreement" shall mean the term "Agreement" as defined in the preamble of this Confirmation.

ARTICLE 9
CONFIDENTIALITY

9.1 The confidentiality provisions in Section 10.11 of the EEI Agreement shall apply herein, except that each of Buyer and Seller may disclose the following information regarding this Confirmation:

(a) Party names;
(b) Resource(s);
(c) Term;
(d) Project name, location(s), and information in Appendix A;
(e) Capacity of each facility designated as the Project;
(f) The fact that a facility designated as the Project is on-line and delivering;
(g) Delivery Point;
(h) The quantity of Product expected or actually delivered under this Confirmation; and
(i) Information provided by Seller pursuant to Section 8.1 of this Confirmation

9.2 Except for disclosures to comply with any applicable regulation, rule, or order of the CPUC, Federal Energy Regulatory Commission, CEC, or other Governmental Authorities, each Party shall provide Notice of any disclosure made pursuant to this Article 9 to the other Party.

ACKNOWLEDGED AND AGREED TO BY EACH PARTY'S DULY AUTHORIZED REPRESENTATIVE OR OFFICER:

PACIFIC GAS AND ELECTRIC COMPANY, a California corporation, limited for all purposes hereunder to its electric procurement and electric fuels functions	[**BUYER, a (*include place of formation and business type*)**]
Signature: ______________________	Signature: ______________________
Name: ______________________	Name: ______________________
Title: ______________________	Title: ______________________
Date: ______________________	Date: ______________________

APPENDIX A to
EEI Master Power Purchase and Sale Agreement
Short Term Sales Confirmation

PROJECT

Name of Facility	Resource	Location	CEC RPS ID	Host Balancing Authority

APPENDIX B

FORM OF LETTER OF CREDIT

Issuing Bank Letterhead and Address

STANDBY LETTER OF CREDIT NO. XXXXXXXX

Date: [*insert issue date]*

Beneficiary:	Pacific Gas and Electric Company 77 Beale Street, Mail Code B28L San Francisco, CA 94105 Attention: Credit Risk Management	**Applicant:**	[Insert name and address of Applicant]

Letter of Credit Amount: [*insert amount]*

Expiry Date: ***[insert expiry date]***

Ladies and Gentlemen:

By order of ***[insert name of Applicant]*** ("Applicant"), we hereby issue in favor of Pacific Gas and Electric Company (the "Beneficiary") our irrevocable standby letter of credit No. ***[insert number of letter of credit]*** ("Letter of Credit"), for the account of Applicant, for drawings up to but not to exceed the aggregate sum of U.S. $ ***[insert amount in figures followed by (amount in words)]*** ("Letter of Credit Amount"). This Letter of Credit is available with ***[insert name of issuing bank, and the city and state in which it is located]*** by sight payment, at our offices located at the address stated below, effective immediately, and it will expire at our close of business on ***[insert expiry date]*** (the "Expiry Date").

Funds under this Letter of Credit are available to the Beneficiary against presentation of the following documents:

1. Beneficiary's signed and dated sight draft in the form of Exhibit A hereto, referencing this Letter of Credit No. ***[insert number]*** and stating the amount of the demand; and

2. One of the following statements signed by an authorized representative or officer of Beneficiary:

   A. "Pursuant to the terms of that certain EEI Power Purchase and Sale Agreement (the "Agreement"), dated ***[insert date of the Agreement]***, between Beneficiary and ***[insert name of Seller under the Agreement]*****,** or any Confirmation thereunder or related thereto**,** Beneficiary is entitled to draw under Letter of Credit No. ***[insert number]*** amounts owed by ***[insert name of Seller under the Agreement]*** under the Agreement; or

   B. "Letter of Credit No. ***[insert number]*** will expire in thirty (30) days or less and ***[insert name of Seller under the Agreement]*** has not provided replacement security acceptable to Beneficiary.

Special Conditions:

1. Partial and multiple drawings under this Letter of Credit are allowed;
2. All banking charges associated with this Letter of Credit are for the account of the Applicant;

3. This Letter of Credit is not transferable; and
4. The Expiry Date of this Letter of Credit shall be automatically extended without a written amendment hereto for a period of one (1) year and on each successive Expiry Date, unless at least sixty (60) days before the then current Expiry Date we notify you by registered mail or courier that we elect not to extend the Expiry Date of this Letter of Credit for such additional period.

We engage with you that drafts drawn under and in compliance with the terms of this Letter of Credit will be duly honored upon presentation, on or before the Expiry Date (or after the Expiry Date in case of an interruption of our business as stated below), at our offices at ***[insert issuing bank's address for drawings]***.

All demands for payment shall be made by presentation of original drawing documents and a copy of this Letter of Credit; or by facsimile transmission of documents to ***[insert fax number]***, Attention: ***[insert name of issuing bank's receiving department]***, with original drawing documents and a copy of this Letter of Credit to follow by overnight mail. If presentation is made by facsimile transmission, you may contact us at ***[insert phone number]*** to confirm our receipt of the transmission. Your failure to seek such a telephone confirmation does not affect our obligation to honor such a presentation.

Our payments against complying presentations under this Letter of Credit will be made no later than on the sixth (6th) banking day following a complying presentation.

Except as stated herein, this Letter of Credit is not subject to any condition or qualification. It is our individual obligation, which is not contingent upon reimbursement and is not affected by any agreement, document, or instrument between us and the Applicant or between the Beneficiary and the Applicant or any other party.

Except as otherwise specifically stated herein, this Letter of Credit is subject to and governed by the *Uniform Customs and Practice for Documentary Credits, 2007 Revision,* International Chamber of Commerce (ICC) Publication No. 600 (the "UCP 600"); provided that, if this Letter of Credit expires during an interruption of our business as described in Article 36 of the UCP 600, we will honor drafts presented in compliance with this Letter of Credit, if they are presented within thirty (30) days after the resumption of our business, and will effect payment accordingly.

The law of the State of New York shall apply to any matters not covered by the UCP 600.

For telephone assistance regarding this Letter of Credit, please contact us at ***[insert number and any other necessary details]***.

Very truly yours,

[insert name of issuing bank]

By: ______________________________
Authorized Signature

Name: ______***[print or type name]***______

Title: ______***[print or type title]***______

[Note: All pages must contain the Letter of Credit number and page number for identification purposes.]

APPENDIX B

FORM OF LETTER OF CREDIT

EXHIBIT A -- SIGHT DRAFT

TO
[INSERT NAME AND ADDRESS OF PAYING BANK]

AMOUNT: $________________________ DATE: __________________________

AT SIGHT OF THIS DEMAND PAY TO THE ORDER OF PACIFIC GAS AND ELECTRIC COMPANY THE AMOUNT OF U.S.$________ (______________ U.S. DOLLARS)

DRAWN UNDER ***[INSERT NAME OF ISSUING BANK]*** LETTER OF CREDIT NO. XXXXXX.

REMIT FUNDS AS FOLLOWS:

[INSERT PAYMENT INSTRUCTIONS]

DRAWER

BY: ________________________________
NAME AND TITLE

APPENDIX F.4

2019 Bundled RPS Energy Sale Solicitation Confidentiality Agreement

March 15, 2019

CONFIDENTIALITY AGREEMENT

This confidentiality agreement ("Confidentiality Agreement") dated as of the last date of signature found at the signature block ("Execution Date") is entered into by and between Pacific Gas and Electric Company, a California corporation, ("PG&E") and ________________ ("Participant"), ***[Participant to insert type of entity]***, each of which may be referred to herein separately as a "Party" or together as the "Parties". ***[Note to Participants: If you have provided a Bid as part of a joint venture or partnership, please insert the names of all parties in interest as Participants.]***

Whereas, each Party ("Provider") may have furnished and is furnishing to the other Party ("Recipient") certain Confidential Information, as defined below, in order to assess Participant's bid to purchase certain product from PG&E as submitted into PG&E's 2019 Bundled RPS Energy Sale Solicitation issued ***[insert date]*** ("Solicitation") pursuant to California Public Utilities Commission Decision (D). 16-12-044 and the negotiation of an agreement ("Agreement") in connection with the Solicitation, if applicable;

Whereas, it is to the mutual benefit of each Party hereto to enter into this Confidentiality Agreement and provide for the procedure to exchange and protect Confidential Information, as defined below, pursuant to this Confidentiality Agreement;

NOW, THEREFORE, in consideration of Provider's disclosure to Recipient of Confidential Information and other valuable consideration, the Parties agree as follows:

1. Definition of Confidential Information

The term "Confidential Information" shall mean all information that either Party has furnished or is furnishing to the other Party, which with respect to Participant as Provider must in addition be clearly marked "Confidential" (or promptly identified in writing as such when furnished to PG&E in intangible form), in connection with or pertaining to the Solicitation or any Agreement bid thereunder, whether furnished before or after the Execution Date of this Confidentiality Agreement, whether intangible or tangible, and in whatever form or medium provided, and regardless of whether owned by Provider, as well as all information generated by Recipient or its Representatives, as defined below, that contains, reflects, or is derived from such furnished information. "Confidential Information" shall also include information regarding the Parties' bidding and negotiation process, including the status of such process, and potential commercial relationship concerning the Solicitation or any Agreement bid thereunder.

2. Disclosure to Representatives

Recipient agrees that it shall maintain the Confidential Information in strict confidence and that the Confidential Information shall not, without Provider's prior written consent, be disclosed by Recipient or by its affiliates, or their respective officers, directors, partners, employees, agents, or representatives (collectively, "Representatives") in any manner whatsoever, in whole or in part, and shall not be used by Recipient or by its Representatives other than in connection with the Solicitation and the evaluation or negotiation of the Agreement; provided that, PG&E may use Confidential Information, consolidated with other market information and not specifically attributed to the Provider, to analyze or forecast market conditions or prices, for its own internal use or in the context of regulatory or other proceedings. Moreover, Recipient agrees to transmit the Confidential Information only to such of its Representatives who need to know the Confidential Information for the sole purpose of assisting Recipient with such permitted uses, as applicable; provided that, Recipient shall inform its Representatives of this Confidentiality Agreement and secure their agreement to abide in all material respects by its terms. In any event, Recipient shall be fully liable for any breach of this Confidentiality Agreement by its Representatives as though committed by Recipient itself.

3. Nondisclosure

Recipient further agrees that it:

(a) shall not disclose any Confidential Information provided to it by Provider to any third party for any purpose, except as provided in Section 5 below (or Section 2 above if a Representative is a third party);

(b) shall not distribute all or any portion of Confidential Information to any Representative for any purpose other than as permitted by Section 2 above; and

(c) shall destroy or return all such Confidential Information upon Provider's request; provided that, each Party shall have the right to retain one copy of Confidential Information for regulatory compliance or legal purposes, and neither Party shall be obligated to purge extra copies of Confidential Information from electronic media used solely for disaster recovery backup purposes.

4. Exclusions to Confidential Information

For purposes of this Confidentiality Agreement, Confidential Information does not include information that:

(a) is in the public domain at the time of the disclosure by Provider or is subsequently made available to the general public through no violation of this Confidentiality Agreement by Recipient;

(b) Recipient can demonstrate was at the time of disclosure by Provider already in Recipient's possession and was not acquired, directly or indirectly, from Provider on a confidential basis;

(c) is independently developed by Recipient without use of or reference to the Confidential Information; or

(d) is disclosed with the prior written consent of Provider.

5. Required and Permitted Disclosure

Recipient agrees not to introduce (in whole or in part) into evidence or otherwise voluntarily disclose in any administrative or judicial proceeding, any Confidential Information, except as required by law or as Recipient may be required to disclose to duly authorized governmental or regulatory agencies ("Required Disclosure"). In the event that Recipient or any of its Representatives becomes subject to a Required Disclosure, Recipient agrees:

(a) to the extent practicable, to use reasonable efforts to notify Provider prior to disclosure and to prevent or limit such disclosure; and

(b) if disclosure of such Confidential Information is required to prevent Recipient from being held in contempt or subject to other legal detriment, to furnish only such portion of the Confidential Information as it is legally compelled to disclose and to exercise its reasonable efforts to obtain an order or other reliable assurance that confidential treatment will be accorded to the disclosed Confidential Information.

After using such reasonable efforts, Recipient shall not be prohibited from complying with the Required Disclosure and shall not be liable to the other Party for monetary or other damages incurred in connection with the Required Disclosure.

In addition to the Required Disclosure, PG&E shall be permitted to disclose Confidential Information as follows: (i) to PG&E's Procurement Review Group ("PRG"), as defined in California Public Utilities Commission ("CPUC") Decision (D) 02-08-071 and subject to confidential treatment by PRG members; (ii) to the CPUC (including CPUC staff) under seal for purposes of review (if such seal is applicable to the nature of the Confidential Information), and (iii) to the Independent Evaluator, as defined and specified in the 2019 Bundled RPS Energy Sale Solicitation Protocol ("Protocol"). PG&E shall also be permitted to disclose Participant's Confidential Information in order to comply with (A) any applicable law, regulation, or any exchange or control area rule, or (B) any applicable regulation, rule, or order of the CPUC, California Energy Commission, the California Air Resources Board, or the Federal Energy Regulatory Commission, including any mandatory discovery or data request issued by any of the foregoing entities.

6. No License Rights

This Confidentiality Agreement and any Confidential Information used or disclosed hereunder shall not be construed as granting, expressly or by implication, Recipient any rights by license or otherwise to such Confidential Information or to any invention, patent or patent application, or other intellectual property right, now or hereafter owned or controlled by Provider.

7. Publicity

Subject to Sections 4 and 5, neither Party will disclose any information or make any news release, advertisement, public communication, response to media inquiry or other public statement regarding this Confidentiality Agreement and the Confidential Information disclosed hereunder (including without limitation the potential commercial relationship between the Parties, the inclusion of a bid on PG&E's shortlist of bids, or the status of negotiations) or the performance hereunder or with respect to a bid, without the prior written consent of the other Party.

8. No Future Contracts

Entry into this Confidentiality Agreement and the disclosure of Confidential Information hereunder shall not constitute a bid or acceptance or promise of any future contract or amendment of any existing contract. Each Party shall retain such rights with respect to its own Confidential Information as it had prior to entering into this Confidentiality Agreement. Neither Party shall have any legal obligation with respect to any contemplated transaction because of this Confidentiality Agreement nor any other written or oral expression with respect to any transaction except, in the case of this Confidentiality Agreement, for the matters specifically agreed to herein.

9. No Representation or Warranties

Any Confidential Information exchanged under this Confidentiality Agreement shall carry no warranties or representations of any kind, either expressed or implied, unless specifically expressed per the terms of the Protocol. Recipient shall not rely on the Confidential Information for any purpose other than to make its own evaluation thereof or as provided in the Protocol.

10. Injunctive Relief

Recipient acknowledges and agrees that, in the event of any breach of this Confidentiality Agreement, Provider may be irreparably and immediately harmed and monetary damages may not be adequate to make Provider whole. Accordingly, it is agreed that, in addition to any other remedy to which it may be entitled in law or equity and, with respect to PG&E as Provider any remedy under the Protocol, Provider shall be entitled to an injunction or injunctions (without the posting of any bond and without proof of actual damages) to cease breaches or prevent threatened breaches of this Confidentiality Agreement and/or to compel specific performance of this Confidentiality Agreement, and that neither Recipient nor its Representatives will oppose the granting of such equitable relief if a court finds a breach or threatened breach. Each Party expressly agrees that it shall bear all costs and expenses, including attorneys' fees and costs that it may incur as Provider in enforcing the provisions of this Confidentiality Agreement.

11. Term and Provisions Surviving Termination

This term of this Confidentiality Agreement shall be two (2) years from the Execution Date; provided however, that either Party may earlier terminate this Confidentiality Agreement by giving the other Party thirty (30) days prior written notice of its intention to terminate this Confidentiality Agreement. Any such expiration or termination shall not abrogate either Party's obligations hereunder with respect to Confidential Information received prior to such expiration or termination nor those terms herein relating to the interpretation or enforcement of this Confidentiality Agreement relating to said obligations. Such obligations and terms shall survive for a period of three (3) years from said expiration or termination.

12. No Waiver

Any waiver of any provision of this Confidentiality Agreement, or a waiver of a breach hereof, must be in writing and signed by both Parties to be effective. Any waiver of a breach of this Confidentiality Agreement, whether express or implied, shall not constitute a waiver of a subsequent breach hereof.

13. Binding Nature and Amendment

This Confidentiality Agreement contains the entire understanding between the Parties with respect to Confidential Information received hereunder. No change or modification shall be effective unless made in writing and signed by an authorized representative of each Party. Any conflict between the language of any legend or stamp on any Confidential Information received hereunder, any provision of the Solicitation Protocol, or Agreement relating to Confidential Information provided during the term of this Agreement, on the one hand, and this Confidentiality Agreement, on the other hand, shall be resolved in favor of the language of this Confidentiality Agreement. This Confidentiality Agreement may not be amended or modified except by a written agreement executed by both Parties.

14. Governing Law and Jurisdiction

THIS CONFIDENTIALITY AGREEMENT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF CALIFORNIA. THE PARTIES AGREE THAT ANY ACTION OR PROCEEDING ARISING OUT OF OR RELATED IN ANY WAY TO THIS CONFIDENTIALITY AGREEMENT SHALL BE BROUGHT SOLELY IN A COURT OF COMPETENT JURISDICTION SITTING IN THE CITY AND COUNTY OF SAN FRANCISCO. THE PARTIES HEREBY IRREVOCABLY AND UNCONDITIONALLY CONSENT TO THE JURISDICTION OF ANY SUCH COURT AND HEREBY IRREVOCABLY AND UNCONDITIONALLY WAIVE ANY DEFENSE OF AN INCONVENIENT FORUM TO THE MAINTENANCE OF ANY ACTION OR PROCEEDING IN ANY SUCH COURT, ANY OBJECTION TO VENUE WITH RESPECT TO ANY SUCH ACTION OR PROCEEDING AND ANY RIGHT OF JURISDICTION ON ACCOUNT OF THE PLACE OF RESIDENCE OR DOMICILE OF ANY PARTY THERETO. THE PARTIES HEREBY IRREVOCABLY AND UNCONDITIONALLY WAIVE THE RIGHT TO A JURY TRIAL IN CONNECTION WITH ANY CLAIM ARISING OUT OF OR RELATED TO THIS CONFIDENTIALITY AGREEMENT.

15. Severability

If any provision hereof is unenforceable or invalid, it shall be given effect to the extent it may be enforceable or valid, and such unenforceability or invalidity shall not affect the enforceability or validity of any other provision of this Confidentiality Agreement.

16. Counterparts

This Confidentiality Agreement may be signed in counterparts, each of which shall be deemed an original. This Confidentiality Agreement may be executed and delivered by facsimile or PDF transmission and the Parties agree that such facsimile or PDF transmission execution and delivery shall have the same force and effect as delivery of an original document with original signatures.

17. Notice

Any notice given hereunder by either Party shall be made in writing and shall be effective once delivered, by any of the following means: (a) e-mail, with indication of complete electronic transmission thereof and receipt of a copy sent via certified U.S. Mail, return receipt requested, as evidenced by a signed delivery receipt; or (b) overnight delivery by a nationally recognized overnight delivery service, as verified by a delivery receipt or signature, addressed as follows:

To Participant: [***TO BE COMPLETED BY EACH PARTICIPANT]***

Name: ___________________________
Address: _________________________
Address: _________________________
Facsimile: ________________________
Email: ___________________________

To PG&E: Pacific Gas and Electric Company
Electric Supply Department
Attn: RFO Manager
77 Beale Street, (MC B25J)
San Francisco, California 94105
Facsimile: (415) 973-3946
Email: RECSolicitations@pge.com

Either Party may periodically change any address to which notice is to be given it by providing written notice of such change to the other Party.

IN WITNESS WHEREOF, each Party has caused this Confidentiality Agreement to be duly executed and delivered by its proper and duly authorized agent as of the date set forth below. ***[Note to Participants: For joint Bids, please add signature blocks for each Participant involved.]***

PACIFIC GAS AND ELECTRIC COMPANY	**[PARTICIPANT NAME]**
Signature	Signature
Print Name	Print Name
Title	Title
Date	Date

Appendix G

Framework for Assessing Potential Sales of Surplus RPS Volumes

March 15, 2019

Appendix G – Framework for Assessing Potential Sales of Renewables Portfolio Standard Volumes

This Appendix describes Pacific Gas and Electric Company's ("PG&E") proposed framework (the "Sales Framework") for assessing whether to hold or sell Renewables Portfolio Standard ("RPS") volumes and only applies to RPS sales with deliveries concluding within the next five calendar years or concluding up to 2020 until after Phase 2 of the PCIA OIR is resolved, depending on the outcome in that proceeding. This Appendix G framework governs only PG&E's 2019 Bundled RPS Energy Solicitations. For purposes of clarity, Appendix J to this Plan, which governs other sales of Tree Mortality Non-Bypassable Charge Renewable Energy Credits, does not apply to the 2019 Bundled RPS Energy Solicitation. This Sales Framework will be updated each year as part of the RPS Plan filing. PG&E may therefore annually adjust its methodology and the resulting calculations of volumes for sale.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted][1] [redacted]

[redacted]

1. [redacted][2]
2. [redacted]
3. [redacted][3]

[redacted]

[1] PG&E may issue more than three solicitations per year. The exact timing and number of solicitations is dependent upon the outcome of prior solicitations and/or changes to PG&E's RPS position.

[2] PG&E uses the phrase "historical long position" to refer to volumes in its existing Bank plus historical RPS volumes that have generated above the annual RPS compliance targets in a current compliance period.

[3] [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

APPENDIX H

Detailed Explanation of PG&E's Least-Cost, Best-Fit Methodology

March 15, 2019

PG&E's Description of its RPS Bid Evaluation, Selection Process and Criteria

I. Introduction

A. Establishment of the Least-Cost, Best-Fit (LCBF) Process

Decision D.03-06-071 and D.04-07-029 adopted criteria for the rank ordering and selection of least cost, best fit renewable resources for use in RPS solicitations. Furthermore, D.05-07-039 directed the IOUs to make their bid evaluation process transparent to their Procurement Review Groups (PRG) and the California Public Utilities Commission (CPUC).

In addition, D.06-05-039 required "each utility to provide a report when it submits its short list of bids. Each utility should also serve a copy on the service list, and make the report available to the fullest extent possible to any other person or party expressing interest, subject to confidential treatment of protected information. The report shall explain each utility's evaluation and selection model, its process, and its decision rationale with respect to each bid, both selected and rejected."

D.06-05-039 also required each IOU to hire an Independent Evaluator ("IE") "to separately evaluate and report on the IOU's entire solicitation, evaluation and selection process for this and all future solicitations. This will serve as an independent check on the process and final selections. The Independent Evaluator's preliminary report should be provided with the IOU's shortlist, and a final report with the AL for approval of selected bids."

The Scoping Memo for R.06-05-027, issued August 21, 2006, required that the IOUs submit their first written report describing their bid evaluation criteria and selection process on September 29, 2006, and that IOUs resubmit the report with their short lists (including more information, such as bid analysis, as necessary). Additionally, in the RPS Transparency Workshop held on December 15, 2006, the CPUC's Energy Division staff proposed, pursuant to D.06-05-039, a template to be used for future evaluation criteria and selection reports ("LCBF Written Report").

D.06-05-039 further required that each IOU include certain elements, subject to confidential treatment of protected information, in each report. These elements include bid-specific price information, the evaluation and scoring of each bid, and the decision rationale with respect to each bid, both selected and rejected. D.11-04-030 added that each utility should describe LCBF treatment of congestion, and to certain price data available. Although PG&E's 2018 RPS Plan does not indicate a need for RPS procurement, PG&E's LCBF protocol may be used in other RFOs for mandated procurement or for RPS energy sales.

B. Goal of PG&E's bid evaluation, selection criteria, and processes

The goal of the bid evaluation, selection criteria, and selection processes is to produce a short list of offers for negotiations consistent with the procurement goals set forth in an RFO.

II. Bid Evaluation and Selection Criteria

A. Overview of the Ranking Methodology

PG&E evaluates each bid in terms of the following quantitative and qualitative attributes:

1. Net Market Value
    a. Benefits (Energy, Capacity, REC, Ancillary Services)
    b. Contract Payments
    c. Transmission Network Upgrade Costs (also called a "transmission adder")
    d. Congestion Cost
2. Portfolio-Adjusted Value
    a. RPS Portfolio Need

3. Qualitative factors

Solicited bids are evaluated using the following step-by-step process:

The Net Market Value (NMV) is computed for each Offer. NMV will be adjusted by other attributes, such as RPS portfolio need, to arrive at the Portfolio-Adjusted Value (PAV). After the calculation of PAV is complete, PG&E considers qualitative criteria listed below. The set of highest ranked Offers which allow for a reasonable probability of satisfying PG&E's procurement goal is selected for the Shortlist or contract execution.

1. Market Valuation

a. Overview of the Market Valuation Criterion

Market valuation considers how an Offer's costs compare to its market benefits. Costs include Transmission Network Upgrade Cost, Congestion Cost and Integration Cost as well as contract payments. Benefits include energy, capacity, and ancillary services values. Specifically, Market Valuation computes NMV for each offer as follows:

$$\text{Net Market Value: } R = (E + C) - (P + T + G + I)$$
$$\text{Adjusted Net Market Value: } A = R + S$$

Where
E = Energy Value
C = Capacity Value
P = Post-Time-Of-Delivery (TOD) Adjusted Power Purchase Agreement (PPA) Price
T = Transmission Network Upgrade Cost
G = Congestion Costs
I = Integration Costs

S = Ancillary Service Value

Costs and Benefits are each quantified and expressed in terms of levelized dollars per MWh. NMV is Benefits minus Costs, and is expressed in terms of levelized dollars per MWh.

The calculation of Benefits, Costs, and Market Value is described below.

b. Calculation of Benefits and PPA Costs

Energy benefit (E), for each hour of delivery, is the value of energy delivered at the market energy price at the corresponding Trading Hub (NP15, SP15, ZP26, Palo Verde), adjusted for Losses, plus the market value of the renewable attribute. As-available (or must-take) energy delivery for each hour from an Offer is determined by the hourly generation profile of the Offer. To the extent that the Offer provides dispatchable capacity, the value of the option from the dispatchability will be captured in the energy benefit calculation. The option value calculation depends on the particular characteristics of the dispatchable capacity. If an Offer includes energy storage that allows PG&E to schedule the discharge and charge of the storage, the energy benefit will also include the additional value that PG&E can realize from being able to shift the RPS energy from the Project to more valuable hours given the constraints of the energy storage.

Losses vary by location of the project and are assessed using the Locational Marginal Price (LMP). The Loss Multiplier for a project delivered to Palo Verde will be 100%. The average Loss Multipliers for a project delivered to CAISO are provided in Table 1. A higher Loss Multiplier implies less loss, thus more value associated with a project located in the corresponding load zone. PG&E may further update the Loss Multipliers based on updated market conditions.

Discounted hourly energy benefit is summed across hours of delivery, and summed across years. The total benefit is then scaled by the delivered energy to be expressed in terms of levelized dollars per MWh.

For offers providing Buyer Curtailment, **energy benefit** will include the option value of the difference between the (presumably negative) wholesale market spot price avoided for the Project and PG&E's cost when Buyer Curtailment occurs.

Capacity benefit (C) for Resource Adequacy (RA), for year of availability, is the projected monthly quantity of qualifying capacity multiplied by the projected monthly capacity price, discounted and summed across years. To the extent that an Offer provides flexible capacity, the capacity that is expected to count for flexible RA and provide the ISO's must-offer requirement for flexible capacity resources will be evaluated at the projected monthly premium (which can be zero or positive) for flexible RA and then added to the Capacity Benefit. There currently exists significant uncertainty regarding the specifics of generic and flexible RA markets in California.

Therefore, the calculation of capacity benefit may evolve as more information is known about market design or as uncertainty lingers.

For an Offer in a location that is projected to contribute to PG&E's satisfaction of a Local Capacity Requirement, the capacity attributable to the Offer may be valued at a premium relative to the value of capacity that satisfies only system needs.

Ancillary Services benefit (S) is assumed to be zero if an Offer doesn't provide any Ancillary Services (A/S) capability. For Offers that provide PG&E the ability to schedule Ancillary Services, the incremental benefit of having A/S capability will be captured, not to be double counted with the energy benefit.

PPA Payments (P) are determined by the expected payments under each Offer including associated debt equivalence costs. The PPA Payment for each hour is calculated by multiplying expected delivery quantity by the Offer's price. The Offer's price is the contract price of the Offer multiplied by the applicable Time of Delivery (TOD) factors specified in the RPS Solicitation Protocol. The hourly PPA Payment is expressed in units of levelized dollars per MWh.

c. Calculation of Transmission Network Upgrade Costs

The Transmission Network Upgrade Costs (T) is the cost, if any, of bringing the power from the generating facility to PG&E's network. PG&E expects to use results from Participants' interconnection studies.

A Present Value Revenue Requirement (PVRR) is calculated from the Interconnection Study for each evaluated bid. If the Seller is offering an energy-only resource, PG&E will use the reliability network upgrades identified in the interconnection study for calculation of the transmission adder. If the Seller is offering a full deliverability resource, PG&E will use both the reliability network upgrades and delivery network upgrades in the calculation. If the resource does not have an interconnection study, PG&E may rely on a cost cap for transmission upgrades proposed by the Participant.

The PVRR captures from a ratepayer perspective the risk and cost to construct and maintain transmission upgrades to accommodate the generation from the renewable resource.

This PVRR of the costs of the Network Upgrades is converted into levelized dollars per MWh.[1]

PG&E may take into account on a qualitative basis the additional value for projects that have no transmission risk.

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[1] Sellers offering full capacity offers may specify when full capacity is to begin and as a result, costs will be reflected accordingly in the PVRR calculation.

d. Congestion Costs

Congestion cost (G) for each hour is calculated by the multiplication of (1) a Congestion Cost Multiplier for the corresponding time period and load zone, (2) the Locational Marginal Price (LMP) of the corresponding Trading Hub, and 3) expected energy delivery.

A project delivered to Palo Verde would be evaluated with Congestion Cost of 0%. A summary of Congestion Cost Multipliers for each load zone in CAISO is included in Table 1. A higher Congestion Cost Multiplier indicates a higher Congestion Cost (G). Specifically, a Congestion Cost Multiplier greater than zero indicates that generation in the corresponding area serves load outside of the area by congested lines and thus a new generation in the corresponding area is expected to increase the congestion. A zero Congestion Cost Multiplier implies there is no congestion in the transmission lines connecting the area. A Congestion Cost Multiplier less than zero indicates that loads in the corresponding area are served by the constrained transmission line(s) and thus a new generation in the area may reduce congestion. PG&E may update the Congestion Cost multipliers as market prices change.

TABLE 1
Congestion Cost Multipliers and Loss Multipliers[2]

			Loss Multipliers		Congestion Cost Multipliers		LMP Multipliers	
			for E		for G		for E-G	
	Descriptive Names	CAISO	On Peak	Off Peak	On Peak	Off Peak	On Peak	Off Peak
1	PG&E Central Coast	PGCC	102.4%	100.5%	2.2%	1.6%	100.2%	98.9%
2	PG&E East Bay	PGEB	101.9%	99.9%	2.1%	1.4%	99.8%	98.5%
3	PG&E Fresno	PGF1	103.1%	102.7%	-2.3%	-6.4%	105.4%	109.0%
4	PG&E Fulton	PGFG	101.5%	98.6%	2.7%	1.3%	98.8%	97.3%
5	PG&E Humboldt	PGHB	103.8%	104.2%	2.6%	2.0%	101.2%	102.2%
6	PG&E Los Padres	PGLP	100.1%	98.3%	3.0%	1.9%	97.0%	96.3%
7	PG&E North Bay	PGNB	102.0%	99.5%	2.8%	1.4%	99.2%	98.0%
8	PG&E North Coast	PGNC	103.0%	98.5%	4.8%	3.6%	98.2%	95.0%
9	PG&E North Valley	PGNV	98.0%	97.4%	2.3%	0.9%	95.7%	96.5%
10	PG&E Peninsula	PGP2	103.0%	100.7%	2.7%	1.3%	100.3%	99.4%
11	PG&E Sacramento	PGSA	100.4%	99.3%	1.8%	0.9%	98.6%	98.4%
12	PG&E South Bay	PGSB	102.6%	100.6%	2.5%	1.2%	100.1%	99.3%
13	PG&E San Francisco	PGSF	104.8%	101.6%	1.7%	1.3%	103.1%	100.3%
14	PG&E Sierra	PGSI	99.9%	99.1%	1.1%	0.9%	98.8%	98.2%
15	PG&E San Joaquin	PGSN	96.7%	96.4%	2.8%	1.4%	93.9%	95.0%
16	PG&E Stockton	PGST	101.0%	99.8%	2.7%	1.4%	98.3%	98.5%
17	So Cal Edison Core	SCEC	96.9%	98.7%	-1.6%	-0.6%	98.5%	99.3%
18	So Cal Edison North	SCEN	96.4%	99.4%	-5.8%	-2.9%	102.2%	102.2%
19	So Cal Edison West	SCEW	98.9%	100.1%	-3.7%	-1.0%	102.6%	101.1%
20	So Cal Edison High	SCHD	92.8%	95.2%	-0.5%	-0.9%	93.3%	96.1%
21	So Cal Edison Low	SCLD	96.0%	97.7%	0.2%	-0.8%	95.8%	98.4%
22	So Cal Edison North	SCNW	96.6%	98.7%	-0.5%	-0.9%	97.1%	99.6%
23	San Diego Gas &	SDG1	99.0%	99.7%	-2.6%	-0.3%	101.7%	100.1%

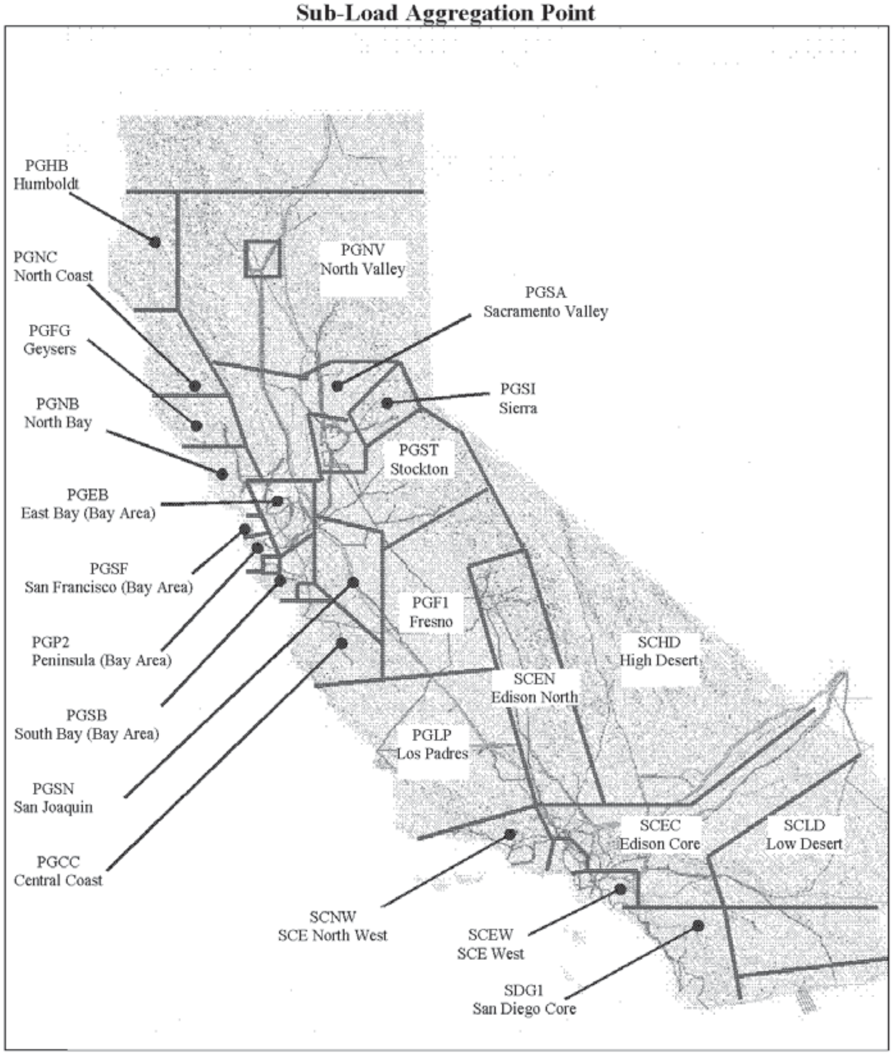
Overall locational value of the project delivered to CAISO should be assessed by looking at the LMP multipliers provided in Table 1. LMP Multiplier for a project delivered to Palo Verde will be 1. The LMP multipliers imply the relative value of 1 MWh in each load zone compared with the corresponding Trading Hub (NP15, SP15, ZP26, or Palo Verde) price. For example, PG&E could consider Offer A located in Sierra and Offer B located in San Francisco, with everything else the same. Offer B will have higher Energy Value (E) because the Loss Multipliers in San Francisco are higher than for the Sierra. On the other hand, Offer A has lower Congestion Cost (G) because the

[2] Multipliers shown are a simple average over hours and months. Contract valuations use disaggregated values for different months.

Congestion Cost Multiplier for Sierra is lower than San Francisco. Overall, Offer B scores higher than Offer A, because E-G will score higher due to higher LMP Multipliers in San Francisco compared with Sierra.

The map for CAISO APNodes is for illustrative purposes only.

Sub-Load Aggregation Point



e. Integration Costs

The renewable integration cost adder (RICA) is calculated using the methodology adopted in D.14-11-042. Renewable integration cost is used in the derivation of Net Market Value per Section 1.a of this document.

The RICA is calculated as the sum of two cost components: 1) variable costs; and 2) fixed costs.

The variable cost component is set at $4/MWh for wind and $3/MWh for solar.

The fixed cost component is calculated as the product of two parameters: 1) PG&E's internal/confidential projection of a monthly premium (which can be zero or positive) for flexible RA expressed as $/kW-month; and 2) the monthly increase (or decrease) in the need for flexible RA associated with one MW of installed capacity of wind or solar ("Contribution to Flexible Capacity Needs") expressed as MW of flex capacity needed/MW of wind or solar capacity.

The Contribution to Flexible Capacity Needs is determined in the following way:

1. Obtain the hourly aggregate system profile for load, wind, and solar.[3]
2. Calculate the hourly three hour net-load ramp for each hour of the year.[4]
3. Identify the maximum three hour net-load ramp for each month, and determine the relative contributions from load, wind, and solar to that ramp.
4. Determine the monthly increase (or decrease) in the need for flexible capacity associated with one MW of installed capacity of wind and solar. This is determined based on the contribution of wind / solar in step 3 and the total installed capacity of wind / solar in the system. For example, if there is 5,000 MW of installed wind and wind's contribution to the maximum three hour net-load ramp in July is 500 MW, then wind's contribution to flexible capacity need is 500 MW / 5,000 MW, or 0.1 MW per 1 MW of installed wind. In this example, 0.1 MW would be the Contribution to Flexible Capacity Needs attributed to a bid for wind generation expected to deliver in that month.

For 2018, PG&E has calculated the Contribution to Flexible Capacity Needs using the four steps above and hourly data from the 2014 Long Term Procurement Plan (LTPP) Trajectory Scenario[5]. The maximum (single hour) wind / solar output from these 2014 LTPP hourly data is used to estimate the total installed capacity for wind / solar in the system. The resulting Contribution to Flexible Capacity Needs for solar and wind are presented in Table 2 below. These numbers may be updated based on supply and demand information adopted in the most recent Integrated Resource Plan (IRP).

[3] Consistent with the CAISO Flexible Capacity Study, the solar PV and solar thermal components are combined. (http://www.caiso.com/Documents/Final_2014_FlexCapacityNeedsAssessment.pdf)
[4] Consistent with the CAISO Flexible Capacity Study, this is the three hour contiguous ramp starting in a given hour of the year, where net-load is defined as load minus wind minus solar
[5] The hourly data can be obtained from the results of the CAISO's 2014 LTPP Production Cost runs. The CAISO posted these results on its LTPP File Transfer Protocol (FTP) website at http://12.200.60.146:990 on July 31, 2014. To help parties access this information, PG&E is also providing these publicly available hourly profiles on its website at www.pge.com/rfo under 2014 Renewables RFO.

TABLE 2
Contribution to Flexible-RA Requirement Per 1 MW of Installed Capacity (MW)

Month	Solar	Wind
JAN	0.52	0.12
FEB	0.75	0.09
MAR	0.63	0.15
APR	0.78	0.13
MAY	0.66	0.01
JUN	0.58	0.07
JUL	0.58	0.04
AUG	0.61	0.05
SEP	0.78	0.20
OCT	0.66	0.02
NOV	0.59	0.00
DEC	0.63	0.20

f. Market Valuation for Offers with Storage

PG&E evaluates the market value from dispatchable storage bundled in an Offer for its ability to (1) shift renewable energy to more valuable hours, (2) provide A/S from stored energy and storage capacity, and (3) provide flexible RA.

PG&E solves for the charge, discharge and A/S schedules that would maximize the value from the project starting from the generation profile without using the energy storage, and the storage constraints provided by the Seller. In order to maximize the spot market value from the project given the assumed market prices for energy and A/S, PG&E will use an optimization technique to obtain the best time and amount to charge, discharge and provide A/S capacity. The spot market value consists of the revenue from energy to be delivered to the grid (the sum of energy that is directly generated from the renewable resource and the energy discharged from storage) and the revenue of A/S capacity to be provided, net of the variable cost from operating. Depending on the energy and A/S prices for a given time period, it may be better to provide A/S, charge renewable energy, discharge stored energy, or do nothing from storage. The Energy Value, A/S Value and PPA Costs in Net Market Value are computed from the assumed market prices as well as the optimized charge, discharge, generation, and A/S schedules.

For Ancillary Services, PG&E asks bidders to specify capability, ramp rates and operating ranges for providing Regulation Up and Down, Spinning Reserve (Spin) and Non-spinning Reserves (Non-spin). When optimizing the schedules, PG&E makes sure that the A/S schedules are within the operating ranges provided and that there is enough energy and storage capacity available. For valuation purposes, PG&E will assume that the value from providing Non-spin in addition to the Spin is negligible because the price for Non-spin is never higher than price for a similar Spin product.

PG&E may include future CAISO A/S products such as flexible ramping product in an optimization to estimate their value if PG&E anticipates that there could be significant incremental value.

Dispatchable storage components that can follow CAISO's day-ahead and real-time dispatch instructions and thus allow PG&E to provide economic bids are expected to count towards meeting PG&E's requirement for flexible RA. Due to the uncertainty about the counting rules that will govern co-located storage components, PG&E will estimate Effective Flexible Capacity (EFC) for renewable offers with storage as a function of MW size and discharge duration of the energy storage component. The calculation of capacity benefit may evolve as more information is known about market rules. The flexible RA Value will be included in the Capacity Value of the Net Market Value.

2. Portfolio Adjusted Value

Portfolio Adjusted Value (PAV) adjustments reflect PG&E's portfolio position and the value to PG&E's portfolio of a purchase or sale.

a. RPS Portfolio Need

PG&E will consider how an Offer contributes to PG&E's overall portfolio need for RPS energy. For a delivery year in which PG&E's portfolio (augmented by the offer) is projected to have lower or higher than targeted RPS-eligible energy, then the PAV Adjustment for the Offer's RPS-eligible energy may be adjusted to a higher or lower value to aid in meeting PG&E's RPS eligible energy targets.

This RPS Portfolio Need adjustment is not duplicative of the Energy Value component of Net Market Value.

Thus, Offers that deliver RPS energy only in periods when PG&E's portfolio needs RPS energy will have higher PAV and rank better than equivalent offers that deliver RPS energy in periods when PG&E's portfolio is long.

3. Qualitative Factors

PG&E may consider qualitative factors including but not limited to:

- Project location in PG&E's service territory
- Project viability: As part of its qualitative assessment of project viability, PG&E will calculate a project viability score using the most recent version of the Project Viability Calculator adopted by the CPUC.
- Impact on disadvantaged communities
- Water use and impact on water quality
- Contribution to state biomass goals
- Contribution to storage targets
- Mark-up of term sheet or PPA
- Contract tenor

- Counterparty concentration
- Technology diversity
- Previous experience with counterparty
- Safety

APPENDIX I

Redline Showing Changes in Final, Conforming 2018 RPS Plan Compared to Revised Draft 2018 RPS Plan Dated October 8, 2018

March 15, 2019

PACIFIC GAS AND ELECTRIC COMPANY

RENEWABLES PORTFOLIO STANDARD

FINAL, CONFORMING ~~REVISED DRAFT~~ 2018 RENEWABLE ENERGY PROCUREMENT PLAN

~~OCTOBER 8, 2018~~
MARCH 15, 2019

CONFIDENTIAL VERSION

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LIST OF APPENDICES

Pacific Gas and Electric Company ("PG&E") respectfully submits its Revised Draft 2018 Renewables Portfolio Standard ("RPS") Plan ("2018 RPS Plan") to the California Public Utilities Commission ("CPUC" or "Commission") as directed by the Commission in the *Assigned Commissioner And Assigned Administrative Law Judge's Ruling Identifying Issues And Schedule Of Review For 2018 Renewables Portfolio Standard Procurement Plans* (the "2018 RPS Plan Ruling").[1] PG&E's 2018 RPS Plan begins with summaries of the key issues and important legislative and regulatory developments impacting California's RPS requirements, and then addresses each of the specific requirements identified in the 2018 RPS Plan Ruling.[2] PG&E has also included in its final 2018 RPS Plan a Framework for Tree Mortality Non-Bypassable Charge Renewable Energy Credit Sales Solicitation, as required by Commission Decision ("D.") 18-12-003.[3] This Framework is set forth in Appendix J.

1. **Summary of Key Issues**

1.1. Assuming No Power Charge Indifference Adjustment Reform, PG&E Has No Need for Additional RPS Resources Until After 2030

PG&E is currently well-positioned to meet its RPS compliance requirements and does not project to have incremental physical need[4] for RPS resources until at least 2026. PG&E projects that it will have incremental RPS procurement need after 2033, after applying volumes of RPS procurement above the requirement from past years

1 2018 RPS Plan Ruling, file June 21, 2018 in Rulemaking ("R.") 15-02-020, p. 21 (Ordering Paragraph ("OP") 1.

2 *See* 2018 RPS Plan Ruling, pp. 2-22.

3 D.18-12-003, OP 3.

4 Situation in which actual deliveries from RPS resources in a given year or compliance period is less than the corresponding RPS interim target or compliance period requirement. In this situation the Bank may be used in part to meet any applicable RPS compliance target.

("Bank") toward its current-year RPS needs beginning in 2026.[5] However, PG&E's RPS need is subject to considerable uncertainty, including the following:

1. If the Joint investor-owned utilities' ("IOU") proposed Green Allocation Mechanism is adopted as part of the Power Charge Indifference Adjustment ("PCIA") Reform proceeding, PG&E's procurement and sales strategies would change dramatically and result in a near-term need for RPS procurement.
2. Expected increases in customers switching to service from Community Choice Aggregators ("CCA") and generating their own electricity have resulted in dramatic decreases in the IOUs' bundled retail sales projections. As retail sales decrease, the quantity of RPS energy required for PG&E to meet its RPS obligation falls, resulting in a decreased need for new RPS resources.
3. The analysis in this 2018 RPS Plan has been updated to incorporate the revised RPS requirements as set forth by Senate Bill ("SB") 100,[6] which was signed by the Governor on September 10, 2018. Otherwise, this 2018 RPS Plan assumes the current RPS law remains unchanged and that the Commission does not exercise its authority to raise the RPS requirements for retail sellers. However, legislation enacted after this date and actions taken in the Commission's RPS proceeding can change these inputs.

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5 In prior versions of its RPS Plan, PG&E has redacted its RPS need year, consistent with the May 21, 2014, Administrative Law Judge's ("ALJ") Ruling on Renewable Net Short ("RNS") issued in R.11-05-005, pages 5 and 24, which established confidentiality rules associated with portfolio optimization. PG&E is waiving this confidentiality in this limited instance in order to allow for public transparency concerning PG&E's proposals to manage its RPS portfolio and concerning PG&E's need for incremental mandated procurement. In doing so, PG&E reserves the right to redact its need year and similar portfolio optimization information in future versions of its RPS Plan. The ability to redact future need is particularly critical when PG&E expects a near-term net short position.

6 SB 100, Stats. 2018, Ch. 312 (De León).

1.2. PG&E Proposes Not to Hold a Solicitation to Procure in 2019

Given its current RPS compliance position, PG&E is proposing not to hold an RPS procurement solicitation for the 2018 solicitation cycle. PG&E will seek Commission approval to procure any incremental RPS products during this RPS Plan cycle, other than the mandated programs referenced below.

Although many factors, including those described above, could change its RPS compliance position, PG&E believes that its existing portfolio of executed RPS contracts, its owned RPS-eligible generation, and its expected Bank balances will be more than adequate to ensure compliance with near-term RPS requirements. Additionally, even without an RPS solicitation, PG&E expects to continue to procure additional volumes of incremental RPS-eligible contracts through mandated procurement programs during the 2018 solicitation cycle (which is expected to occur during the calendar year 2019).[7]

1.3. PG&E Plans to Continue to Sell RPS Volumes in 2019

As load has shifted to non-IOU suppliers and developers have overcome early obstacles in the RPS Program and projects have become increasingly viable, PG&E has shifted from a focus on incremental procurement to now managing and optimizing its existing RPS portfolio, including through sales of RPS volumes. PG&E proposes to pursue ~~both~~ short-term ~~and~~RPS sales in 2019. Additionally, PG&E may pursue long-term RPS sales ~~in 2019.~~after Phase 2 of the Power Charge Indifference Adjustment Rulemaking ("PCIA OIR") is resolved, depending on the outcome in that proceeding. This will help to address the fact that PG&E's forecasted RPS position predicts a higher

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7 Mandated programs include Renewable Market Adjusting Tariff ("ReMAT~~") and~~"), the Bioenergy Market Adjusting Tariff ("BioMAT~~").~~"), and any new or extended biomass contracts pursuant to SB 901. The ReMAT program is currently the subject of litigation in federal court, and the Commission has issued a new Order Instituting Rulemaking ("OIR") to consider further implementation of the Federal Public Utility Regulatory Policies Act of 1978 ("PURPA"), which will consider adoption of a new mandate to procure from RPS-eligible facilities that are Qualifying Facilities ("QF") under federal law. *See generally* R.18-07-017. In addition, while it will not directly impact PG&E's RNS, PG&E expects to procure additional volumes over the next year for the Green Tariff Shared Renewables ("GTSR") Program.

cumulative Bank than its calculated minimum Bank needed to ensure compliance in light of regular fluctuations in supply and demand.

In 2018, PG&E issued a second solicitation for sales of RPS products and participated in other retail sellers' RPS procurement solicitations. PG&E used its Commission-approved RPS sales framework (the "RPS Sales Framework") to assess sales opportunities. PG&E is updating the RPS Sales Framework as part of this 2018 RPS Plan and intends to use the revised RPS Sales Framework, if approved, in 2019 to target issuing three, with a minimum of two, sales solicitations.[8]

The goal of PG&E's RPS Sales Framework is to prudently manage PG&E's portfolio with a focus on customer affordability, while continuing to maintain compliance with the RPS Program. As described more fully in Section 4, below, updates proposed in this RPS planning cycle to the RPS Sales Framework may result in significantly higher volumes of sales from PG&E's RPS portfolio in 2019 than occurred in 2018. If the market conditions support sales at the highest levels allowed under the proposed revisions to the RPS Sales Framework, the volumes would far exceed the ~2,000 gigawatt-hour ("GWh") per year assumed, based on the results of PG&E's 2017 sales solicitation, for purposes of quantitative modeling in this 2018 RPS Plan. If sales at the higher volumes allowed by revisions to the RPS Sales Framework were realized in 2019, the higher volumes would be incorporated into PG&E's RNS calculations going forward and included in future RPS Plans.

The volume of sales at the high end allowed by the revised RPS Sales Framework would cause physical deliveries of RPS-eligible products to PG&E to fall well below the annual RPS interim targets and compliance period statutory requirements in some future years. However, PG&E projects that it will be able to comply with all existing RPS requirements in the near-term even under a scenario in which it executes the maximum volume of sales proposed by the revised RPS Sales

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8 Additional detail on PG&E's planned sales solicitations is described in Section 4.

Framework since it has adequate volumes in its historical long position[9] to make up any difference between physical deliveries and the near-term RPS requirements.

It is unclear whether market participants will offer prices for RPS-eligible products at levels that would result in selling the maximum volumes of RPS-eligible products allowed by the revised RPS Sales Framework. In the past, PG&E has not received sufficient market interest in order to sell all of the volumes it has offered in solicitations. Nonetheless, for the reasons described more fully in Section 4, it is in the interest of PG&E's customers to attempt to sell significantly higher volumes of RPS products in this RPS planning cycle to the extent the level of market demand sustains adequate prices.

1.4. PG&E Opposes Mandates That Result in Unnecessary and/or Unreasonable Costs for Its Customers

Despite PG&E's absence of need for additional RPS resources, PG&E continued in 2018 to procure required RPS-eligible volumes through mandated procurement programs such as the BioMAT program and the solar photovoltaic Renewable Auction Mechanism ("PV RAM") program. In 2017, for example, PG&E held 18 auctions/solicitations[10] to fulfill mandated program requirements, despite being granted approval by the Commission to not hold an RPS solicitation due to lack of RPS need.

Wherever consistent with law, PG&E will continue to oppose new RPS procurement mandates, to seek to suspend existing RPS procurement mandates, and to oppose any changes to existing RPS procurement mandates that would require additional procurement. In general, PG&E believes that no RPS procurement should be mandated without a clear demonstration of need.

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9 Throughout this 2018 RPS Plan, PG&E uses the phrase "historical long position" to refer to volumes in its existing Bank plus historical RPS volumes that have generated above the annual RPS compliance targets in a current compliance period.

10 PG&E has held bi-monthly auctions for ReMAT since November 1, 2013 (until the program was suspended at the end of 2017, as further described below) and for BioMAT since February 1, 2016. PG&E also held one PV RAM solicitation in 2018.

Even if PG&E had near-term RPS need, PG&E would still not support expansion of existing mandated programs or additional new mandated programs. Mandated procurement programs do not optimize costs for customers because they restrict flexibility and optionality to achieve the RPS targets by mandating procurement through a potentially less efficient and more costly manner. PG&E supports a technology-neutral procurement process, in which all RPS-eligible technologies can compete to demonstrate which projects provide the best value to customers at the lowest cost.

Finally, PG&E continues to be concerned about the cost burden that procurement mandates place on bundled customers and will seek to ensure all customers, both bundled and departed load, equitably bear the costs of additional and existing mandates. Mandated procurement through Bioenergy Renewable Auction Mechanism ("BioRAM"), BioMAT, ReMAT, and the PV RAM benefits all customers and thus all customers should pay their equitable share of those costs.

1.5. PG&E's RPS Procurement and Sales Strategies Are Highly Dependent on the Resolution of the PCIA Reform Proceeding

The Commission is considering whether and how to revise the existing PCIA in R. 17-06-026. While the Commission issued a Proposed Decision ("PD") in that proceeding on August 1, 2018, a final decision will not be adopted prior to the filing of the draft version of this 2018 RPS Plan. Until the Commission issues a final decision in its PCIA reform docket, the RPS portfolio position and RPS procurement and sales strategies described in this draft plan are highly uncertain and contingent.[11]

This Plan may need updates, or even need to be re-filed, if the PCIA Reform proceeding concludes in a decision that allocates significant portions of PG&E's RPS portfolio to other retail sellers, as the joint IOUs have proposed in R.17-06-026. That decision would materially impact PG&E's RNS position, as described more fully in the following sub-section.

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11 PG&E notes that the PD issued ins R.17-06-026 would not eliminate these uncertainties and contingencies even if adopted as proposed. The PD would initiate a new phase of R.17-06-026 in which the Commission will continue to consider portfolio management and may direct PG&E to take actions that impact its current RPS position.

Unless otherwise explicitly noted, the analysis provided in this draft version of the 2018 RPS Plan assumes no reform of the existing PCIA, and therefore no allocation of PG&E's RPS portfolio to other retail sellers. If the final decision issued in R.17-06-026 revises the PCIA methodology in a way that impacts PG&E's RNS, PG&E will either incorporate those changes into an update of the 2018 RPS Plan according to the schedule set forth in the 2018 RPS Plan Ruling, as amended,[12] or it will seek permission to revise or re-file its 2018 RPS Plan on another timeline.

2. Summary of Important Recent Legislative/Regulatory Changes to the RPS Program

PG&E's portfolio forecast and procurement decisions are influenced by legislative and regulatory changes related to the RPS Program. While bills recently signed by the Governor will likely change PG&E's RPS position and need, the quantitative analysis provided in this 2018 RPS Plan only considers statutes enacted as of September 19, 2018. Legislation enacted after September 19, 2018, that will likely impact PG&E's RNS in the future, depending on how these bills are implemented, includes SB 237,[13] which is expected to increase the participation cap for the State's Direct Access program by 4,000 GWh statewide, and SB 901,[14] which requires the IOUs to seek to extend the delivery terms of RPS-eligible biomass contracts that meet certain feedstock and other requirements. Resolution E-4977, which amends the BioRAM Program pursuant to SB 901, requires PG&E to seek additional procurement from certain BioRAM and other biomass contracts. However, the volume of the additional procurement and the terms of the procurement are unknown at this time and are thus not reflected in the RNS calculations. Any executed contract extensions

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12 See Administrative Law Judge Mason's E Mail Ruling Granting, in part, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company Request for Extension to the 2018 RPS Plan Schedule, sent to the Service List for R.15-02-020 on July 9, 2018 (extending deadline for filing Motions to Update the Draft RPS Plans to September 28, 2018).

13 SB 237, Stats. 2018, Ch. 600 (Hertzberg). SB 237 requires the Commission to issue an order implementing SB 237 by June 1, 2019.

14 SB 901, Stats. 2018, Ch. 626 (Dodd).

pursuant to SB 901 will be reflected in future RNS and RPS Plan updates. As a general matter, PG&E expects that implementation of SB 237 and SB 901 will increase PG&E's long position with regard to the RPS targets and so will not change the fundamental proposals in this 2018 RPS Plan to pursue RPS sales and to not undertake a procurement solicitation in 2019.

The following section summarizes recent legislative and regulatory developments that may impact PG&E's RPS Program. Specifically, this section addresses: (1) the adoption of SB 100; (2) the adoption and implementation of SB 350; (3) mandated procurement programs, including RAM, ReMAT, bioenergy procurement program ("BioRAM"), and BioMAT; (4) the pending Integrated Resource Plan ("IRP") proceeding at the CPUC; (5) the approved Diablo Canyon Retirement Joint Proposal Application; ~~and~~ (6) the pending PCIA reform proceeding at the Commission~~.~~; and (7) the pending implementation of Procurement Expenditure Limitation ("PEL").

2.1. Adoption of Senate Bill 100

On September 10, 2018, Governor Brown signed SB 100, known as the 100 Percent Clean Energy Act of 2018. SB 100 increases the statutory RPS requirements to 44 percent by the end of 2024; 52 percent by the end of 2027; and 60 percent by 2030 and thereafter. PG&E's quantitative analysis in this 2018 RPS Plan, including its RNS tables, reflect these increased targets. Separately, SB 100 adopts a statewide policy that 100 percent of California's retail sales must come from RPS-eligible and zero-carbon resources by 2045.

2.2. Adoption and Implementation of Senate Bill 350

On October 7, 2015, Governor Brown signed SB 350, known as the Clean Energy and Pollution Reduction Act of 2015. Among other provisions, SB 350 increased the RPS target from 33 percent in 2020 to 50 percent in 2030. On April 15, 2016, ALJ Simon issued a ruling to begin implementation of SB 350 provisions relating to RPS procurement, including establishing post-2020 compliance periods and making changes to the banking provisions and long-term procurement requirements.[15]

On December 15, 2016, the Commission adopted ~~Decision ("D.")~~ D.16-12-040, which implements the new compliance periods and Procurement Quantity Requirements ("PQR")[16] for the RPS Program as revised by SB 350.

On June 29, 2017, the Commission adopted D.17-06-026, which implements new compliance requirements for the California RPS program in response to changes made by SB 350. The Decision addresses the implementation of new rules for the use of long-term contracts in RPS compliance for all compliance periods beginning January 1, 2021. The new long-term requirement provides that, beginning January 1, 2021, at least 65 percent of the procurement a retail seller counts toward the RPS requirement of each compliance period must be from long term contracts. The Decision also: (1) implements new rules for applying excess procurement in one compliance period to later compliance periods beginning January 1, 2021; (2) provides direction for early compliance with the new long-term contract and excess procurement rules in the 2017-2020 compliance period; and (3) integrates changes made by SB 350 into the ongoing RPS compliance process.

In order to elect the early compliance option provided in SB 350, a retail seller must give notice of its election not later than 60 days from the effective date of D.17-06-026. PG&E gave notice on August 17, 2017, by letter addressed to the Director of Energy Division and served on the service list for R.15-02-020 of its election to comply early with the new long term and excess procurement requirements. Also in compliance with D.17-06-026, PG&E filed a motion on September 22, 2017 to update its RPS Procurement Plan to, among other things, reflect its election to comply early with

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15 *Administrative Law Judge's Ruling Requesting Comments on Implementation of Elements of Senate Bill 350 Relating to Procurement under the California Renewables Portfolio Standard*, issued April 15, 2016.

16 As implemented by the Commission, a PQR is the total volume of ~~Renewable Energy Credits (REC)~~RECs that a retail seller~~-~~ must retire for compliance with the RPS in each respective multi-year RPS compliance period.

the new long term and excess procurement requirements. Accordingly, the analysis set forth in the 2018 RPS Plan reflects PG&E's expectation that it will be subject to these new long term and excess banking rules beginning in the current 2017-2020 RPS compliance period.

On June 6, 2018, the Commission issued D.18-05-026, in which it implemented certain enforcement and penalty provisions contained in the SB 350 amendments to the RPS statute. Of particular relevance to this 2018 RPS Plan is the requirement in D.18-05-026 that each retail seller must annually demonstrate that transportation electrification is quantitatively accounted for in their RPS procurement plans. PG&E has described how it incorporated transportation electrification into its forecast of retail sales in Section 6.1.2.

Further Commission action on SB 350 implementation, as well as other remaining issues identified in R.15-02-020, may impact PG&E's procurement need and actions going forward.

2.3. Implementation of Mandated Procurement Programs

Existing mandated procurement programs for RPS-eligible resources include BioMAT, ReMAT, and PV RAM. As described below, PG&E continues to seek to procure resources under BioMAT despite a demonstrated lack of need for additional RPS resources. ReMAT has been suspended, and PG&E expects to complete its PV RAM program in 2018.

2.3.1. BioMAT

On September 27, 2012, SB 1122 was passed, requiring California's IOUs to procure a total of 250 megawatts ("MW") of new small-scale bioenergy projects that are 3 MW or less in size through the Feed-In Tariff ("FIT") Program; other Load Serving Entities ("LSE") (publicly-owned utilities), Electric Service Providers ("ESP"), CCAs) do not have this procurement obligation. Because all customers benefit equally from mandated procurement through BioMAT, all customers should contribute equitably to their costs. The total IOU mandate is allocated into three technology categories with separate MW targets: (1) 110 MW of biogas from wastewater plants and green waste; (2) 90 MW of dairy and other agriculture bioenergy; and (3) 50 MW of forest waste biomass. On December 18, 2014, the Commission issued D.14-12-081 to implement SB 1122, requiring the IOUs to file a tariff and contract for SB 1122 eligible generation. The IOUs filed their proposed contract and tariff on February 6, 2015, which were approved with modifications in D.15-09-004. PG&E's SB 1122 Program (BioMAT) began accepting participants on December 1, 2015 and the first program period (auction) was held on February 1, 2016. PG&E has held bimonthly BioMAT auctions since February 2016.

On October 28, 2016, the Commission issued D.16-10-025, which retained the current BioMAT pricing structure, clarified interconnection requirements, and ordered that the BioMAT sustainable forest management fuel use category (Category 3) include fuel obtained from high hazard zones). D.16-10-025 also amended eligibility requirements for interconnection and set monthly auctions for Category 3 projects.

On November 28, 2017, the Commission issued a letter setting a temporary price cap (which will be in place, pending the CPUC's review of the BioMAT program) for sustainable forest management projects at $199.72/megawatt-hours ("MWh") unless projects can attest to using 60% High Hazard Fuel. PG&E filed Advice Letter ("AL") 5285-E on May 2, 2018 making these program modifications. This advice letter was suspended on May 31, 2018 and as of August 5, 2018, PG&E is preparing to file a supplemental advice letter with minor modifications.

On December 6, 2017, the *Winding Creek Solar LLC v. Peevey* court decision[17] found the ReMAT Program to violate the federal PURPA. The court found that ReMAT was non-compliant with PURPA because: (1) the price is not reflective of the Utility's avoided cost and (2) the program megawatt cap violates PURPA's must-take obligation. Given BioMAT has the same programmatic structure as ReMAT, PG&E refrained from

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17 *Winding Creek Solar Llc v. Peevey*, 293 F.Supp.3d 980 (N.D. CA 2017) (available at https://www.leagle.com/decision/infdco20171207935).

executing any BioMAT contracts until the CPUC addressed PG&E's concerns with the legality of the contracts in light of the *Winding Creek* court decision. On May 31, 2018, the Commission issued D.18-05-032, ordering the IOUs to modify the BioMAT contract to remove the representation that the contract does not violate any laws. As ordered by Resolution ("Res.") E-4922, PG&E executed the 10 outstanding Power Purchase Agreements ("PPA") (14.34 MW) on June 12, 2018, which included the modifications ordered in D.18-05-032. PG&E also filed a Tier 1 Advice Letter on June 21, 2018 acknowledging the execution of these contracts and the removal of the "any laws" language in those contracts. Outside of the temporary hold on executing BioMAT PPAs prior to June 12, 2018, the BioMAT program continues to operate and seek new procurement.

On a parallel track, the Commission issued D.17-08-021 instructing the IOUs to make changes to the PPA and tariff to reflect the ability for bioenergy facilities that are newly eligible with a nameplate capacity of up to 5 MW (per Assembly Bill ("AB") 1923) to be able to participate in the program. PG&E filed AL 5144-E-A with these changes, which the Commission approved on March 26, 2018.

On May 10, 2018, the Governor issued an Executive Order B-52-18[18] related to wildfire risk and the improvement of forest management and restoration. Item 16 requests that the Commission review and update its procurement programs for small bioenergy renewable generators.

2.3.2. ReMAT

ReMAT was established in May 2012 when the Commission made several revisions to its FIT program. These changes included increasing the eligible project size from 1.5 MW to 3 MW, establishing a 750 MW program cap, and adopting the

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18 Executive Order B-52-18 of Governor Edmund G. Brown, Jr., May 10, 2018 (available at https://www.gov.ca.gov/wp-content/uploads/2018/05/5.10.18-Forest-EO.pdf).

ReMAT pricing mechanism.[19] IOUs and publicly owned electric utilities were allocated a share of the 750 MW program cap; other LSEs (ESPs and CCAs) do not have this procurement obligation. Because all customers benefit equally from the mandated procurement through ReMAT, all customers should contribute equitably to their costs. PG&E has held bi-monthly auctions for ReMAT resources since November 1, 2013.

On December 6, 2017, the Winding Creek Solar LLC v. Peevey court decision[20] found the ReMAT Program to violate the federal PURPA. The court found that ReMAT was non-compliant with PURPA because: (1) the price is not reflective of avoided cost and (2) the program MW cap violates PURPA's must-take obligation. On December 5, 2017, the Executive Director of the CPUC issued a letter ordering the three IOUs to refrain from signing new ReMAT contracts, suspend holding any ReMAT program periods, and to stop accepting new applications for the program. As a result, all ReMAT program activity is currently on hold.

2.3.3. PV Program Procurement Through RAM (PV RAM)

In D.14-11-042, the Commission granted PG&E's petition to transfer approximately 200 MW from PG&E's PV Program to the Renewable Auction Mechanism 6 solicitation and two additional solicitations. On July 24, 2018, PG&E submitted AL 5330-E to the Commission, seeking approval for a PPA that would meet the final remaining procurement obligation pursuant to the original PV Program.

2.4. Coordination With the Integrated Resource Planning Process

In February 2018, the Commission issued D.18-02-018, which identified the CPUC's Reference System Plan using the RESOLVE model to determine the optimal California Independent System Operator ("CAISO")-wide portfolio of resources to meets the State's policy goals of achieving a 40 percent reduction in Greenhouse Gas ("GHG")

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19 See D.12-05-035, *Decision Revising Feed-in-Tariff Program, Implementing Amendments to Public Utilities Code Section 399.20 Enacted by Senate Bill 380, Senate Bill 32, and Senate Bill 2 1X and Denying Petitions for Modification of Decision 07-07-027 by Sustainable Conservation and Solutions for Utilities, Inc.*, issued May 31, 2012.

20 https://www.leagle.com/decision/infdco20171207935.

emissions below 1990 levels by 2030, a 50 percent RPS mandate by 2030, and adequate resources to ensure system reliability requirements. D.18-02-018 also set the guidelines for LSEs to determine their own IRPs, allowing use of either the IRP's GHG planning price or a mass-based LSE GHG target. On August 1, 2018, PG&E filed its IRP, containing a Preferred scenario based on its latest internal load forecast that showed it can comply with both the 50% RPS target as well as its LSE GHG target without the need for additional incremental renewable procurement.[21] This 2018 RPS Plan continues to model PG&E's RPS need based upon the existing statutory requirements, including the recently signed SB 100.

PG&E expects that outcomes from future IRP cycles will link more closely with resource-specific procurement processes and proceedings, such as the RPS Procurement Plan.[22] Going forward, PG&E supports close alignment between the IRP and the RPS proceeding, with the IRP comparing RPS resources against other GHG-free resources, including demand-side alternatives such as Energy Efficiency ("EE") and rooftop solar.

2.5. Diablo Canyon Retirement Joint Proposal Application

On August 11, 2016, PG&E and the Joint Parties[23] filed an Application requesting Commission approval of the retirement of Diablo Canyon nuclear power plant. In the Joint Proposal, PG&E proposed to adopt a voluntary 55 percent RPS

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[21] As stated in its 2018 IRP, PG&E has no incremental procurement need for new RPS or GHG-free resources through 2030; PG&E can meet its 2030 GHG planning target with its existing GHG-free resource portfolio and resources added to comply with existing mandates.

[22] Modeled results shown in this RPS Plan are generally consistent with PG&E's 2018 IRP except that the RPS Plan reflects minor updates to PG&E's RPS generation portfolio and includes some stochastically simulated results that are inherently variable.

[23] Friends of the Earth, Natural Resources Defense Council, Environment California, International Brotherhood of Electrical Workers Local 1245, Coalition of California Utility Employees, and the Alliance for Nuclear Responsibility.

energy target beginning in 2031.[24] The Commission issued D.18-01-022 on January 16, 2018, approving PG&E's proposal to retire Diablo Canyon, stating the Commission's intent to avoid GHG emissions increase from Diablo Canyon's retirement, and that the need for replacement procurement should be addressed in the IRP proceeding. On September 19, 2018, Governor Brown signed SB 1090[25] that would, among other things, require the Commission to ensure the integrated resources plans avoid any increase in GHG emissions as a result of retiring the Diablo Canyon nuclear power plant.

2.6. Order Instituting Rulemaking to Review, Revise, and Consider Alternatives to the PCIA

The Commission issued an OIR to Review, Revise, and Consider Alternatives to the PCIA on June 29, 2017 (the PCIA OIR).[26] The PCIA OIR is a much-needed forum to address the broken, out-of-date system for allocating costs of long-term energy contracts and generation resource investments.

PG&E is committed to developing PCIA reform solutions that treat all customers fairly and equally, and that support California's clean energy goals. On April 2, 2018, the IOUs jointly filed testimony[27] in the PCIA OIR docket proposing a new PCIA methodology, which would involve the allocation of RECs to other parties. If the IOUs' proposed methodology, or a similar methodology, were approved by the Commission, that decision would affect PG&E's RPS compliance position and would cause PG&E to

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24 See A.16-08-006, Application of Pacific Gas and Electric Company for Approval of the Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, And Recovery of Associated Costs Through Proposed Ratemaking Mechanisms. The voluntary 55 percent by 2031 commitment in the Joint Proposal has recently been superseded by the higher statutory requirement of 60 percent by 2030 and thereafter. *See* SB 100, Stats. 2018, Ch. 312.

25 SB 1090, Stats. 2018, Ch. 561 (Monning).

26 See R.17-06-026.

27 See Joint IOU Prepared Testimony submitted in R. 17-06-026 on April 2, 2018 (available at http://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R1706026/1407/214907587.pdf).

procure additional RPS resources earlier than currently anticipated.[28] The Commission issued a PD and an alternate PD in the PCIA OIR in August 2018, and the earliest date on which the Commission may adopt a final decision is October 11, 2018.[29]

2.7. Cost Containment

In meeting its RPS requirements, PG&E has made every effort to procure least-cost and best-fit renewable resources. However, recognizing the potential cost impact that RPS procurement can have on customers, PG&E supports the establishment of a clear, stable, and meaningful Procurement Expenditure Limitation ("PEL") that both informs procurement planning and decisions, and promotes regulatory and market certainty. Implementation of the PEL has been pending at the Commission since SB 2 (1X) required the establishment of the PEL in 2011. PG&E urges the Commission to establish a PEL in order to protect customers from excessive costs, particularly from above-market, resource-specific RPS procurement mandates.

3. Assessment of RPS Portfolio Supplies and Demand

3.1. Supply and Demand to Determine the Optimal Mix of RPS Resources

Meeting California's RPS goals in a way that achieves the greatest value for customers continues to be a top priority for PG&E. In particular, PG&E continues to analyze its need to procure cost-effective resources that will enable it to achieve and maintain California's RPS targets. Under existing law,[30] PG&E is required through 2030 to retire sufficient numbers of RECs from RPS-eligible products to meet the following RPS requirements:

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28 See PG&E's 2018 Integrated Resource Plan, Alternative Scenario beginning on Page 63 (available at http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=511341).

29 McKinney, Jeanne "Re: Rulemaking 17-06-026 - Courtesy Notice" September 24, 2018. Email.

30 PG&E is assuming, for purposes of this 2018 RPS Plan, that the Commission will implement the SB 100 revised targets in the same "straight-line" manner as it implemented prior versions of the statutory RPS targets.

- 2017-2020 (Third Compliance Period): A percentage of the combined bundled retail sales that is consistent with the following formula: (.27 * 2017 retail sales) + (.29 * 2018 retail sales) + (.31 * 2019 retail sales) + (.33 * 2020 retail sales);
- 2021-2024: A percentage of the combined bundled retail sales that is consistent with the following formula: (.358 * 2021 retail sales) + (.385 * 2022 retail sales) + (.413 * 2023 retail sales) + (.44 * 2024 retail sales);[31]
- 2025-2027: (.467 * 2025 retail sales) + (.493 * 2026 retail sales) + (.52 * 2027 retail sales); and
- 2028-2030: (.547 * 2028 retail sales) + (.573 * 2029 retail sales) + (.60 * 2030 retail sales).

Based on preliminary results presented in Appendix A.2, PG&E delivered 33.0 percent of its power from RPS-eligible renewable sources in 2017.

As described more fully in Section 8 and reported in the current RNS calculations in Appendix A.2, based on forecasts and expectations of the ability of contracted resources to deliver, PG&E is well-positioned to meet its RPS compliance requirements through compliance period ("CP 5") (2025-2027). Under the 60 percent RPS by 2030 target, 60 percent RPS annually thereafter PG&E projects that it will not have incremental RPS physical need until 2026, and a procurement need beginning after 2033, after applying the Bank beginning in 2026. PG&E's RPS position will be updated annually to reflect any sales of RPS volumes.

3.2. Supply

3.2.1. Existing Portfolio

PG&E's existing RPS portfolio is comprised of a variety of technologies, project sizes, and contract types. The portfolio includes approximately 8,000 MW of projects online or under development, ranging from the following: (a) utility-owned solar and small hydro generation; (b) long-term RPS contracts for large wind, geothermal, solar,

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31 Compliance period requirements in 2021 and after are based on D.16-12-040, issued by the CPUC on December 20, 2016, which implemented the new compliance periods and PQR established pursuant to SB 350.

and biomass generation; and (c) small FIT contracts for solar PV, biogas, and biomass generation. This robust and diversified supply provides a solid foundation for meeting current and future compliance needs; however, the portfolio is also subject to uncertainties as discussed below and in more detail in Sections 7 and 8.

As described in further detail in Section 7.2, to model the project failure variability inherent in project development, PG&E assumes that project viability for a to-be-built project is a function of the number of years until its contract start date. This success rate is evolving and highly dependent on the nature of PG&E's portfolio, the general conditions in the renewable energy industry, and the timing of the RPS Plan publication date relative to recent project terminations.

Consistent with the project trends reported in its 2017 RPS Plan, PG&E has observed continued progress of key projects under development in its portfolio. Tax incentives (e.g., the federal Investment Tax Credit ("ITC") and Production Tax Credit ("PTC")) have helped the development of the market for renewables. PG&E expects renewables to continue to be cost-competitive in the future, whether or not the ITC and PTC are extended. Progress in the siting and permitting of projects also has supported PG&E's sustained high success rate. As described in more detail in this section, PG&E believes the renewable development market has stabilized for the near-term and the renewable project financing sector will continue to evolve well into the future.

Notwithstanding these positive trends, the timely development of renewable energy facilities remains subject to many uncertainties and risks, including regulatory and legal uncertainties, permitting and siting issues, technology viability, adequate fuel supply, and the construction of sufficient transmission capacity. These challenges and risks are described in more detail in the remainder of Section 3.

For purposes of calculating its demand for RPS-eligible products through the modeling described in Section 7, PG&E does not assume that expiring RPS-eligible contracts in its existing portfolio are re-contracted.

3.2.2. Impact of Green Tariff Shared Renewables Program

In 2013, SB 43 enacted the GTSR Program allowing PG&E customers to meet up to 100 percent of their energy usage with generation from eligible renewable energy resources. On January 29, 2015, the Commission issued D.15-01-051 implementing a GTSR framework, approving the IOUs' applications with modifications, and requiring the IOUs to begin procurement for the GTSR Program in advance of customer enrollment. In January 2016, PG&E's GTSR Program opened for enrollment under the program name "PG&E's Solar Choice." The most recent GTSR Annual Report for the program was filed with the Commission on March 15, 2018.

The GTSR Program impacts PG&E's RPS position in two ways: (1) PG&E's RPS supply may be affected as described below; and (2) retail sales will be reduced corresponding to program participation. D.15-01-051 permits the IOUs to supply Green Tariff customers from an interim pool of existing RPS resources until new dedicated Green Tariff projects come online. Generation from these interim facilities would no longer be counted toward PG&E's RPS targets, which will result in a decrease in PG&E's RPS supply. However, there is also a possibility that PG&E's RPS supply could increase in the future if generation from Green Tariff dedicated projects exceeds the demand of Green Tariff customers. In this case, those volumes procured for GTSR would then be added to PG&E's RPS portfolio, even if PG&E had no RPS need. PG&E has developed tracking and reporting protocols for tracking RECs transferred to and from the RPS portfolio and Green Tariff Programs.

In conformance with D.15-01-051[32] and as described in the Joint Procurement Implementation Advice Letter, PG&E reports annually on the amount of generation transferred between the RPS and GTSR Programs in a report that is filed by September 1 each calendar year. PG&E filed its first Annual GTSR Tracking Report on August 30, 2016, reporting that no generation transferred between the RPS and GTSR Programs in program year 2015. The second report that included generation transfer

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[32] *See* D.15-01-051, p. 50.

between the RPS and GTSR programs was filed for program year 2016 on September 1, 2017. The third-generation transfer report for program year 2017 will be filed by September 1, 2018. In both 2016 and 2017, the sales of solar electricity under PG&E's Solar Choice Program were covered by the interim pool of existing solar resources from the RPS program; hence, the generation transfer occurred from the RPS program to the Solar Choice program. As described above, starting in 2018, the sales under the Solar Choice program will be covered by the PG&E's Solar Choice Program dedicated resources procured specifically for the Program. As more capacity was procured under the program than is currently needed for Solar Choice customers, generation will be transferred from the PG&E's Solar Choice Program to the RPS program in 2018.

For purposes of this 2018 RPS Plan, PG&E updated the RNS calculations to reflect expected GTSR Program impacts on retail sales and RPS supply through 2036.

3.2.3. RPS Market Trends and Lessons Learned

As its renewable resource portfolio has expanded to meet RPS goals, PG&E's procurement strategy has evolved. PG&E's strategy continues to focus on the following four key goals: (1) reaching, and sustaining, the existing RPS targets; (2) minimizing customer cost within an acceptable level of risk; (3) ensuring PG&E maintains an adequate Bank of surplus RPS volumes to manage annual load and generation uncertainty; and (4) aligning PG&E's RPS portfolio to its customers' needs. PG&E is continually adapting its strategy to accommodate new emerging trends in the California renewable energy market and regulatory landscape.

The California renewable energy market has developed and evolved significantly over the past few years. The market now offers a variety of technologies at generally lower prices than seen in earlier years of the RPS Program. The share of these technologies in PG&E's portfolio is changing as a result. For some technologies, such as PV, prices have dropped significantly due to various factors including technological breakthroughs, government incentives, and improving economies of scale as more projects come online.

Another trend, driven by the growth of renewable resources in the CAISO system, is the downward movement of mid-day wholesale energy market prices. Many renewable energy project types have minimal operating costs, and therefore additions of these renewables tend to move wholesale energy market clearing prices down. This has led to a change in the energy values associated with RPS offers, with decreasing value for renewable projects that generate during mid-day hours.

The growth of renewable resources also has produced challenges, such as negative wholesale energy market prices. Provisions that provide PG&E with greater flexibility to economically bid RPS-eligible resources into the CAISO markets are critical to helping address negative pricing situations that are likely to increase in the future. These provisions have customer benefits. Economic bidding enables RPS-eligible resource generation to be curtailed during negative pricing intervals when it is economic to do so, which protects customers from higher costs. Economic curtailment is discussed in greater detail in Section 12.

3.3. Demand

PG&E's demand for RPS-eligible resources is a function of multiple complex factors including regulatory requirements and portfolio considerations. Key RPS compliance requirements were established in D.11-12-020, D.12-06-038, and D.16-12-040. These requirements will need to be implemented by the Commission to incorporate the revised statutory RPS targets in the recently enacted SB 100.

One RPS compliance criterion of particular importance is that involving the need to ensure a balanced RPS portfolio. Implementing Section 399.16 of the Public Utilities Code ("Pub. Util. Code"), the Commission issued D.11-12-052 to define three statutory portfolio content categories ("PCC") of RPS-eligible products that retail sellers may use for RPS compliance, which impacts PG&E's demand for different types of RPS-eligible products. The ultimate effect of these portfolio balancing requirements is to significantly increase the demand of LSEs, including PG&E, for resources that are directly interconnected or deliver in real time to a California Balancing Area like CAISO.

Finally, PG&E's demand is a function of the risk factors discussed in more detail in Section 6; in particular, uncertainty regarding bundled retail sales can have a major impact on PG&E's demand for RPS resources, as further detailed below.

3.3.1. Near-Term Need for RPS Resources

Because PG&E has no incremental procurement need until after 2033 under existing RPS requirements, PG&E is proposing to not hold an RPS solicitation for the solicitation cycle for the year 2019. PG&E has sufficient time in the coming years to respond to changing market, load forecast, or regulatory conditions and will reassess the need for future Request for Offers ("RFO") in next year's RPS Plan. Although many factors could change PG&E's RPS compliance position, PG&E believes that its existing portfolio of executed RPS-eligible contracts, its owned RPS-eligible generation, and its expected Bank balances will be adequate to ensure compliance with near-term RPS requirements. Additionally, PG&E expects to continue procurement of additional volumes of incremental RPS-eligible contracts in 2019 through mandated procurement programs, such as the PV RAM and BioMAT Programs. PG&E will seek permission from the Commission should PG&E intend to procure any incremental RPS volumes other than amounts separately mandated by the Commission during the time period covered by the 2018 RPS Plan.

3.3.2. Portfolio Considerations

One of the most important portfolio considerations for PG&E is the forecast of bundled load. Currently, PG&E is projecting a decrease in retail sales in 2018 and a continued retail sales decrease through 2025, followed by modest growth thereafter. These changes are driven by the increasing impacts of EE, customer-sited generation, and CCA participation levels, and are offset slightly by an improving economy and growing electrification of the transportation sector. As described in more detail in

Section 7.2.1, PG&E uses its stochastic model to simulate a range of potential retail sales forecasts.

In addition to retail sales forecasts, as discussed in Sections 7, 8 and 9, PG&E's long-term demand for new RPS-eligible project deliveries is driven by: (1) PG&E's current projection of the success rate for its existing RPS portfolio, which PG&E uses to establish a minimum margin of procurement; and (2) the need to account for PG&E's risk-adjusted need, including any Voluntary Margin of Procurement ("VMOP") as determined by PG&E's stochastic model. The risk and uncertainties that justify the need for VMOP are further detailed and quantified in Sections 7 and 8.

3.4. Anticipated Renewable Energy Technologies and Alignment of PG&E's Portfolio With Expected Load Curves and Durations

PG&E's procurement evaluation methodology considers both market value and the portfolio fit of RPS-eligible resources in order to determine PG&E's optimal renewables product mix. With the exception of specific Commission-mandated programs and the PV Program, PG&E does not identify specific renewable energy technologies or product types (e.g., baseload, peaking as-available, or non-peaking as-available) that it is seeking to align, or fit, with specific needs in its portfolio. Instead, PG&E identifies an RPS-eligible energy need in order to fill an aggregate open position identified in its planning horizon and selects project offers that are best positioned to meet PG&E's current portfolio needs. This is evaluated through the use of PG&E's Portfolio Adjusted Value ("PAV") methodology, which ensures that the procured renewable energy products provide the best fit for PG&E's portfolio at the least cost. Starting with its 2014 RPS RFO, PG&E began utilizing the interim integration cost adder to accurately capture the impact of intermittent resources on PG&E's portfolio

3.5. RPS Portfolio Diversity

PG&E's RPS portfolio contains a diverse set of technologies, including PV, solar thermal, wind, small hydro, bioenergy, and geothermal projects in a variety of geographies, both in-state and out-of-state. PG&E's procurement strategy addresses technology and geographic diversity on a quantitative and qualitative basis.

In the Net Market Value ("NMV") valuation process, PG&E models the location-specific marginal energy and capacity values of a resource based on its forecasted generation profile. Thus, if a given technology or geography becomes "saturated" in the market, then those projects will see declining energy and capacity values in their NMV. This aspect of PG&E's valuation methodology should result in PG&E procuring a diverse resource mix if technological or geographic area concentration is strong enough to change the relative value of different resource types or areas. In addition, technology and geographic diversity may have the potential to reduce integration challenges. PG&E's use of the integration cost adder in its NMV valuation process may also result in the procurement of different technology types.

Diversity is also considered qualitatively when making procurement decisions. Resource diversity may decrease risk to PG&E's RPS portfolio given uncertainty in future hourly and locational market prices as well as technology-specific development risks.

PG&E recognizes that resource diversity is one option to minimize the overgeneration and integration costs associated with technological or geographic concentration. PG&E believes, as a general principle, that less restrictive procurement structures, in contrast to mandated programs, will provide the best opportunity to maximize value for its customers. Less restrictive procurement structures also will enable proper responses to changing market conditions and more competition between resources. PG&E further believes that geographic or technology-specific mandates add additional costs to RPS procurement.

3.6. Optimizing Cost, Value, and Risk for the Ratepayer

The costs of the RPS Program are becoming more apparent on customer bills as RPS projects have come online in significant quantities. In addition to cost impacts resulting from the direct procurement of renewable resources, customer costs are also impacted by the associated indirect incremental transmission and integration costs.

PG&E is aware of these direct and indirect cost impacts and will attempt to mitigate them whenever possible. PG&E's fundamental strategy for mitigating RPS cost impacts is to balance the opposing objectives of: (1) delaying additional RPS-related costs until deliveries are needed to meet compliance requirements; (2) managing the risk of being caught in a "seller's market," where PG&E faces potentially high market prices in order to meet near-term compliance deadlines, and (3) selling renewables in accordance with its framework described in Appendix G. When these objectives are combined with the general need to manage overall RPS portfolio volatility based on demand and generation uncertainty, PG&E believes it is prudent and necessary to maintain an adequate Bank through the most cost-effective means available.[33]

In addition, PG&E seeks to minimize the overall cost impact of renewables over time through promoting competitive processes that can encourage price discipline, and using the Bank to mitigate risks associated with load uncertainty, project failure, and generation variability. PG&E generally supports the use of competitive procurement mechanisms that are open to all RPS-eligible technologies and project sizes. As described in greater detail in Section 13, the cost impacts of mandated procurement programs that focus on particular technologies or project sizes may increase the overall costs of PG&E's RPS portfolio for customers as procurement from these programs comprise a larger share of PG&E's incremental procurement goals. This further underscores the need to implement an RPS cost containment mechanism that provides a cap on costs. PG&E supports a technology-neutral procurement process where all technologies can compete to offer the best value to customers at the lowest cost. Finally, as described in Sections 4 and 10, as part of its overall RPS position and management strategy, and with the goal of increasing cost-effectiveness, PG&E is

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33 When considering sales, PG&E considers selling its entire historical long position (including any calculated minimum bank) if its future need is beyond five years.

proposing updates to its previously-approved framework for the sale of RPS volumes that returns revenue from sales to its customers.

3.7. Long-Term RPS Optimization Strategy

PG&E's long-term optimization strategy seeks to both achieve and maintain RPS compliance through and beyond 2030 and to minimize customer cost within an acceptable level of risk. Although PG&E remains mindful of meeting near-term compliance targets, it also seeks to refine strategies for maintaining compliance in a least-cost manner in the long-term (i.e., post-2030). PG&E's optimization strategy includes an assessment of compliance risks and approaches to protect against such risks by maintaining a Bank that is both prudent and needed to achieve the RPS compliance requirements. PG&E employs two models in order to optimize cost, value, and risk for the ratepayer while achieving sustained RPS compliance. This optimization analysis results in PG&E's "stochastically-optimized net short" ("SONS"), which PG&E uses to guide its procurement strategy, as further described in Sections 7 and 8.

PG&E's long-term optimization strategy includes three primary components: (1) incremental procurement (if needed); (2) possible sales of surplus procurement; and (3) effective use of the Bank. Although PG&E is proposing to not hold a 2018 RPS procurement solicitation, future incremental procurement aimed at avoiding the need to procure extremely large volumes in any single year remains a component of PG&E's long-term RPS optimization strategy. In addition to procurement, PG&E's optimization strategy includes sales of surplus procurement that provide a value to customers. PG&E has developed a framework for sales, which was approved in previous iterations by the CPUC, and is provided in Appendix G.

The third component of the optimization strategy is effective use of the Bank. Under the existing RPS targets and current market assumptions, PG&E plans to apply a portion of its projected Bank to meet compliance requirements beginning in 2026. Additionally, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in PG&E's stochastic model, while maintaining a minimum Bank size of at least [redacted]. Section 8 below provides additional information regarding the use and size of PG&E's Bank.[34]

4. RPS Position Management and Sales of RPS Products

As described in Section 8.2, PG&E forecasts its cumulative Bank to exceed the calculated minimum Bank size over the next 10 years, in part due to dramatic recent and ongoing changes to PG&E's retail sales forecast. Accordingly, PG&E continues to seek authority in this 2018 RPS Plan to sell RPS volumes from its portfolio through short-term sales under the updated RPS Sales Framework in Appendix G, and long-term sales in Section 4.4 as described below.

4.1. Updates to the RPS Sales Framework

The goal of PG&E's RPS Sales Framework is to prudently manage its portfolio with a focus on customer affordability, while continuing to maintain compliance with the RPS Program. PG&E will continue to seek and evaluate opportunities to execute short-term contracts to sell RPS-eligible products from its portfolio under the sales framework. These short-term sales would be for volumes to be delivered in the years 2019-2023, or through the year 2020 until after Phase 2 of the PCIA OIR is resolved, depending on the outcome in that proceeding.

The overall intent of PG&E's proposed changes to its RPS Sales Framework in this 2018 RPS Plan is to further the approved Framework's objectives of maximizing value for customers while maintaining compliance with RPS requirements. The updated framework would allow for the potential of significantly higher volumes of sales than were historically executed [redacted]. Under the Sales Framework in Appendix G, PG&E will establish an amount of gross volumes available for sale, with flexible sales quantities to be sold based on market pricing.

34 *Ibid.*

The objective of PG&E's updated Sales Framework is to return to a balanced RPS position in a timely manner, and mitigate price risk to customers, by adhering to the following principles:

- Compliance: Ensure PG&E can maintain compliance with RPS requirements;
- Value for Customers: Ensure value for customers [redacted]; and
- Flexibility: Adapt to a fluctuating market and policy landscape through annual revisions in the RPS Plan filing.

In comparison to the approved 2017 RPS Sales Framework, PG&E is proposing several refinements aimed at simplifying the implementation process, maximizing revenue for customers, and balancing PG&E's RPS position, which has lengthened due to current and forecasted CCA departure and the high viability of projects in PG&E's existing portfolio. Below are the main refinements PG&E is proposing:

- [redacted][35] [redacted]

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35 As an illustrative example, a total volume limit of 100,000 GWh divided by 20 years is 5,000 GWh. The total divided by 25 years is 4,000 GWh.

[redacted]

- [redacted]
- [redacted]

[redacted]

4.2. Implications of the Updated Sales Framework

A key aspect of the updated RPS Sales Framework is that it may result in volumes of sales significantly higher than the approximately 2,000 GWh forecasted in its RNS table, if there is sufficient market demand. Specifically, under a high demand scenario, PG&E could sell [redacted]

[redacted].
Additionally, even if the market demand is sufficient to sustain adequate prices to sell volumes of RPS products at the high end of the RPS Sales Framework, PG&E will be able to utilize volumes accumulated in its historical long position to satisfy its compliance obligations.

This is consistent with PG&E's overarching strategy to optimize its RPS position by using its historical long position to minimize customer costs while maintaining RPS compliance. Given that volumes in PG&E's historical long position have more value if PG&E retires them for RPS compliance than if they are sold into the market (since the PCC 1 or PCC 0 RECs in PG&E's Bank would become PCC 3 products when sold as unbundled RECs and used by a third-party for RPS compliance), it is prudent for PG&E to preserve the higher compliance value of its historical long position by selling future deliveries of bundled RPS products to third parties. This may cause PG&E's physical deliveries in a given year to fall below the RPS interim target or multi-year compliance period requirements, in which case PG&E will use volumes in its historical long position to meet compliance requirements. [redacted]

[redacted] [36] [redacted]

36 [redacted]

[redacted] These percentages represent a book-end scenario; actual sales and the resulting physical RPS position in these years will depend on market demand, fluctuations in load, and fluctuations in the output of the RPS contracts in PG&E's portfolio.

4.3. Implementation of the RPS Sales Framework

Based on current inputs to the framework described in Appendix G, PG&E will target issuing three, with a minimum of two, solicitations for the sale of bankable, bundled renewable generation and RECs in 2019.[37] PG&E anticipates selling short-term products (meaning contracts of five years or less in duration) based on its position.

PG&E intends to execute sales ~~primarily through PG&E-initiated solicitations. However, if PG&E continues to have significant volumes available for sale after issuing its own sales solicitation(s), PG&E may consider entering into bilateral contracts outside of PG&E-initiated sales solicitations (including through participation in other LSEs' procurement solicitations).~~through PG&E-initiated solicitations. Confidential Appendix F contains PG&E's sales solicitation protocol and pro forma sales agreement. The pro forma sales agreement is largely unchanged from the 2018 Bundled RPS Energy Sale Short Form Confirm approved in the 2017 RPS Plan cycle. The final protocol represents a streamlined approach to selling RPS energy, with the primary selection criterion being price. As discussed in Section 10.4 below, PG&E anticipates minimal discussions with buyers with respect to the form agreement.

PG&E will file short-term sales agreements resulting from a solicitation~~, or bilateral transactions~~ that ~~both: (1)~~ are negotiated based upon the pro forma sales agreement ~~and (2) are executed after PG&E receives bids for a sales solicitation resulting from its Final 2018 RPS Plan~~, with any necessary modifications, as Tier 1

37 PG&E may issue more than three solicitations per year. The exact timing and number of solicitations will depend on the outcome of prior solicitations and/or changes to PG&E's RPS position.

Advice Letters for Commission approval.[38] ~~Bilateral sales transactions that do not use the pro forma sales agreement or are not executed after PG&E receives bids for a sales solicitation resulting from its Final 2018 RPS Plan will be filed as Tier 3 Advice Letters.[39]~~

4.4. Long-Term Sales

PG&E ~~expects to~~may hold at least one solicitation for long-term sales in the future after Phase 2 of the PCIA OIR is resolved, depending on the outcome in that proceeding. Offering long-term sales allows PG&E to offer its RPS products to a broader market. Additionally, it provides PG&E an opportunity to gauge demand for long-term products. To ensure that PG&E does not exceed the total volumes that it may sell under the RPS Sales Framework, the proposed updated RPS Sales Framework will consider volumes to be offered for long-term sales, ensuring these volumes are not sold as part of the short-term sale solicitations. PG&E is reserving the amount described in Confidential Appendix G for long-term offers because: (1) it is unclear if a robust market exists for long-term sales; (2) it is unclear if the market values long-term products more than short term products; and (3) selling too much long-term product could impact PG&E's ability to comply with policy changes in the future that cause an incremental need for that long-term volume. PG&E will file any executed long-term RPS sales agreements for Commission approval through an Application after Phase 2 of the PCIA OIR is resolved, depending on the outcome in that proceeding.

5. Project Development Status Update

PG&E, Southern California Edison Company, and San Diego Gas & Electric Company file monthly RPS Database submissions with the CPUC. These monthly submissions contain a larger collection of data on each RPS project than previously provided in the IOUs' Project Development Status Reports. Project development status

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38 D.17-12-007, OP 7; D.14-11-042, p. 77.

~~39 *Id.*~~

updates for RPS contracts can now be obtained from the publicly available data published on the Commission's website at http://cpuc.ca.gov/RPS_Reports_Data.

6. Potential Compliance Delays

This Section addresses factors, including those identified in the RPS statute, that may impact PG&E's ability to comply with its near-term RPS requirements or its need for a statutory waiver of those requirements.[40] While in general PG&E does not currently foresee obstacles to achieving compliance with existing RPS requirements, market conditions and changes in law and regulatory requirements could change this outlook in the future.

6.1. Consideration of Compliance Delay Risks in PG&E's RPS Strategy

Despite PG&E's current expectation that it will be able to comply on time with existing RPS requirements, significant market, operational, or regulatory changes could impact that assessment. This section describes briefly some of the risks and the steps PG&E is taking to mitigate these risks.

6.1.1. Curtailment of RPS Generating Resources

As discussed in more detail in Section 12, if RPS curtailed volumes increase substantially due to CAISO market or reliability conditions, curtailment may reduce the RPS energy available for compliance. In order to better address this challenge, PG&E's stochastic model incorporates estimated levels of curtailment, which enables PG&E to plan for appropriate levels of RPS procurement to meet RPS compliance even when volumes are curtailed. Additional detail on these assumptions is provided in Section 7.2.

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40 This section is not intended to provide a detailed justification for an enforcement waiver or a reduction in the portfolio content requirements pursuant to Sections 399.15(b)(5) or 399.16(e). To the extent that PG&E finds that it must seek such a waiver or portfolio balance reduction in the future, it reserves the right to set forth a more complete statement, based upon the facts as they appear in the future, in the form of a petition or as an affirmative defense to any action by the Commission to enforce the RPS compliance requirements.

6.1.2. Transportation Electrification

PG&E's retail sales forecast is adjusted for expected load increases due to plug-in electric vehicle ("EV") adoption. In order to consider the impact of EVs on PG&E's annual load, PG&E developed an internal probabilistic assessment of EV penetration, leveraging: (1) aggregated EV registration data available through summer 2017; (2) policy goals declared through summer 2017 as well as modeling of compliance for existing policy; (3) EV adoption scenarios developed by ICF International, Inc. in the California Electric Transportation Coalition's Transportation Electrification Assessment; and (4) inputs describing typical EV electricity consumption and charging behavior. PG&E did not directly leverage the California Energy Commission's ("CEC") 2017 Integrated Energy Policy Report ("IEPR") transportation electricity demand forecast in developing its EV forecast. PG&E and the CEC use two fundamentally different modelling approaches, with PG&E using a policy-driven adoption model (top down) and the CEC using a consumer choice model (bottom-up). Thus, modeling assumptions are not easily transferable between the two approaches. However, PG&E did compare its EV forecast results against the CEC's results and found PG&E's forecast to be about 25% higher than the CEC forecast for PG&E's service territory in 2030. In addition to using different modeling approaches, PG&E and the CEC use different input assumptions that may impact the forecast results. For example, PG&E's EV forecast considers growth in the rideshare market, whereas the CEC IEPR forecast does not.

6.1.3. Risk-Adjusted Analysis

As more fully described in the following section, PG&E employs both a deterministic and stochastic approach to quantifying its remaining need for incremental renewable volumes. PG&E's experience with RPS procurement is that developers often experience difficulties managing some of the development issues described above. As described in Section 9, PG&E's expected RPS need calculation incorporates a minimum margin of procurement to account for some anticipated project failure and delays in PG&E's existing portfolio.

While it has made reasonable efforts to minimize risks of project delays or failures in an effort to comply with the 60 percent RPS Program procurement targets, PG&E cannot predict with certainty the circumstances—or the magnitude of the circumstances—that may arise in the future affecting the renewables market or individual project performance.

7. Risk Assessment

Dynamic risks, such as the factors discussed in Section 6 that could lead to potential compliance delays, directly affect PG&E's ability to plan for and meet compliance with the RPS requirements. As described elsewhere in this RPS Plan, PG&E is currently well-positioned to meet its RPS compliance requirements and its risk of non-compliance is low. Nevertheless, to account for these and additional uncertainties in future procurement, PG&E models the demand-side risk of retail sales uncertainty and the supply-side risks of generation variability, project failure, curtailment, and project delays in quantitative analyses.

Specifically, PG&E uses two approaches to modeling risk: (1) a deterministic model; and (2) a stochastic model. The deterministic model tracks the expected values of PG&E's RPS target and deliveries to calculate a "physical net short," which represents a point-estimate forecast of PG&E's RPS position and constitutes a reasonable minimum margin of procurement, as required by the RPS statute. These deterministic results serve as the primary inputs into the stochastic model. The stochastic model[41] accounts for additional compounded and interactive effects of various uncertain variables on PG&E's portfolio to suggest a procurement strategy at least cost within a designated level of non-compliance risk. The stochastic model provides target procurement volumes for each compliance period, which result in a designated Bank size for each compliance period. The Bank is then primarily utilized as VMOP to mitigate dynamic risks and uncertainties and ensure compliance with the RPS.[42]

This section describes in more detail PG&E's two approaches to risk mitigation and the specific risks modeled in each approach. Section 7.1 identifies the three risks accounted for in PG&E's deterministic model. Section 7.2 outlines the four additional risks accounted for in PG&E's stochastic model. Section 7.3 describes how the risks described in the first two sections are incorporated into both models, including details about how each model operates and the additional boundaries each sets on the risks. Section 7.4 notes how the two models help guide PG&E's optimization strategy and procurement need. Section 8 discusses the results for both the deterministic and stochastic models and introduces the physical and optimized net short calculations presented in Appendices A.1 and A.2. Section 9 addresses PG&E's approach to the statutory minimum and voluntary margins of procurement.

7.1. Risks Accounted for in Deterministic Model

PG&E's deterministic approach models three key risks:

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41 The stochastic model specifically employs both Monte Carlo simulation of risks and genetic algorithm optimization of procurement amounts. A Monte Carlo simulation is a computational algorithm commonly used to account for uncertainty in quantitative analysis and decision making. A Monte Carlo simulation provides a range of possible outcomes, the probabilities that they will occur and the distributions of possible outcome values. A genetic algorithm is a problem-solving process that mimics natural selection. That is, a range of inputs to an optimization problem are tried, one-by-one, in a way that moves the problem's solution in the desired direction—higher or lower—while meeting all constraints. Over successive iterations, the model "evolves" toward an optimal solution within the given constraints. In the case of PG&E's stochastic model, a genetic algorithm is employed to conduct a first-order optimization to ensure compliance at the identified risk threshold while minimizing cost.

42 PG&E has also developed a framework to assess whether to hold or sell RPS volumes, included in Appendix G.

1) Standard Generation Variability: the assumed level of deliveries for categories of online RPS projects.

2) Project Failure: the determination of whether or not the contractual deliveries associated with a project in development should be excluded entirely from the forecast because of the project's relatively high risk of failure or delay.

3) Project Delay: the monitoring and adjustment of project start dates based on information provided by the counterparty (as long as deliveries commence within the allowed delay provisions in the contract).

The table below shows the methodology used to calculate each of these risks, and to which category of projects in PG&E's portfolio the risks apply. More detailed descriptions of each risk are described in the subsections below.

TABLE 7-1
DETERMINISTIC MODEL RISKS

Risk	Methodology	Applies to
Standard Generation Variability	• For non-QF projects executed post-2002, 100% of contracted volumes • For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries • Hydro QFs, Utility-Owned Generation ("UOG") and Irrigation District and Water Agency ("ID&WA") generation projections are updated to reflect the most recent hydro forecast.	Online Projects
Project Failure	• In Development projects with high likelihood of failure are labeled "OFF" (0% deliveries assumption) • All other In Development projects are "ON" (assume 100% of contracted delivery)	In Development Projects
Project Delay	• Professional judgment/Communication with counterparties	Under Construction Projects/ Under Development Projects/ Approved Mandated Programs

7.1.1. Standard Generation Variability

With respect to its operating projects, PG&E's forecast is divided into three categories: non- QF; non-hydro QFs; and hydro QF projects. The forecast for non-QF projects is based on contracted volumes. The forecast for non-hydro QFs is typically based on the average of the three most recent calendar year deliveries. The forecast for hydro QFs is typically based on historical production, normalized for average water year conditions, and then adjusted to reflect PG&E's latest internal hydro outlook. The UOG and ID&WA forecast are based on PG&E's latest internal hydro updates. Future years' hydro forecasts assume average water year production. These assumptions are included in this RPS Plan as Appendix D.

7.1.2. Project Failure

To account for the development risks associated with securing project siting, permitting, transmission, interconnection, and project financing, PG&E uses the data collected through PG&E's project monitoring activities in combination with best professional judgment to determine a given project's failure risk profile. PG&E categorizes its portfolio of contracts for renewable projects into two risk categories: OFF (represented with 0 percent deliveries) and ON (represented with 100 percent deliveries). This approach reflects the reality of how a project reaches full development; either all of the generation from the project comes online, or none of the generation comes online.

1. **OFF/Closely Watched** – PG&E excludes deliveries from the "Closely Watched" projects in its portfolio when forecasting expected incremental need for renewable volumes. "Closely Watched" represents deliveries from projects experiencing considerable development challenges as well as once-operational projects that have ceased delivering and are unlikely to restart. In reviewing project development monitoring reports, and applying their best professional judgment, PG&E managers may consider the following factors when deciding whether to categorize a project as "Closely Watched":
    - Actual failure to meet significant contractual milestones (e.g., guaranteed construction start date, guaranteed commercial operation date, etc.);
    - Anticipated failure to meet significant contractual milestones due to the project's financing, permitting, and/or interconnection progress or to other challenges (as informed by project developers, permitting agencies, status of CAISO transmission studies or upgrades, expected interconnection timelines, and/or other sources of project development status data);
    - Significant regulatory contract approval delays (e.g., 12 months or more after filing) with no clear indication of eventual authorization;

- Developer's statement that an amendment to the PPA is necessary in order to preserve the project's commercial viability;
- Whether a PPA amendment has been executed but has not yet received regulatory approval; and
- Knowledge that a plant has ceased operation or plant owner/operator's statement that a project is expected to cease operations.

Final forecasting assessments are project-specific and PG&E does not consider the criteria described above to be exclusive, exhaustive, or the sole criteria used to categorize a project as "Closely Watched."[43] PG&E does not currently have any in-development projects categorized as "OFF" in its deterministic model.

2. **ON** – Projects in all other categories are assumed to deliver 100 percent of contracted generation over their respective terms. There are three main categories of these projects. The first category, which denotes projects that have achieved commercial operation or have officially begun construction, represents the majority of "ON" projects. Based on empirical experience and industry benchmarking, PG&E estimates that this population is highly likely to deliver. The second category of "ON" projects is comprised of those that are in development and are progressing with pre-construction development activities without foreseeable and significant delays. The third category of "ON" projects represents executed and future contracts from Commission-mandated programs. While there may be some risk to specific projects being successful, because these volumes are mandated, the expectation is that PG&E will replace failed volumes within a reasonable timeline.

7.1.3. Project Delay

Because significant project delays can impact the RNS, PG&E regularly monitors and updates the development status of RPS-eligible projects from PPA execution until commercial operation. Through periodic reporting, site visits, communication with counterparties, and other monitoring activities, PG&E tracks the

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43 For instance, PG&E may elect to count deliveries from projects that meet one or more of the criteria if it determines, based on its professional judgment, that the magnitude of challenges faced by the projects do not warrant exclusion from the deterministic forecast. Similarly, the evaluation criteria employed by PG&E could evolve as the nature of challenges faced by the renewable energy industry, or specific sectors of it, change.

progress of projects towards completion of major project milestones and develops estimates for the construction start (if applicable) and commercial operation of projects.

7.2. Risks Accounted for in Stochastic Model

The risk factors outlined in the deterministic model are inherently dynamic conditions that do not fully capture all of the risks affecting PG&E's RPS position. Therefore, PG&E has developed a stochastic model to better account for the compounded and interactive effects of various uncertain variables on PG&E's portfolio. PG&E's stochastic model assesses the impact of both demand- and-supply-side variables on PG&E's RPS position from the following four categories:

1) Retail Sales Uncertainty: This demand-side variable is one of the largest drivers of PG&E's RPS position;
2) Project Failure Variability: Considers additional project failure potential beyond the "on-off" approach in the deterministic model;
3) Curtailment: Considers buyer-ordered (economic), CAISO-ordered or Participating Transmission Owner ("PTO") -ordered curtailment; and
4) RPS Generation Variability: Considers additional RPS generation variability above and beyond the small percentages in the deterministic model.

When considering the impacts that these variables can have on its RPS position, PG&E organizes the impacts into two categories: (1) persistent across years; and (2) short-term (e.g., effects limited to an individual year and not highly correlated from year to year). Table 6-2 below lists the impacts by category, while showing the size of each variable's overall impact on PG&E's RPS position.

TABLE 7-2
CATEGORIZATION OF IMPACTS ON RPS POSITION

	Impact	Categorization
Higher Impact on RPS Position	**1. Retail Sales Uncertainty:** Changes in retail sales tend to persist beyond the current year (e.g., economic growth, EE, CCA and DA, and distributed generation impacts).	**Variable and persistent** *(If an outcome occurs, the effect persists through more than one year).*
	2. Curtailment: Impact increases with higher penetration of renewables and will be persistent.	**Variable and persistent**
	3. RPS Generation Variability: Variability in yearly generation is largely an annual phenomenon that has little persistence across time.	**Variable and short-term** *(If an outcome occurs, the effect may only occur for the individual year.)*
Lower Impact on RPS Position	**4. Project Failure Variability:** Lost volume from project failure persists through more than one year.	**Variable and persistent**

7.2.1. Retail Sales Variability

PG&E's retail sales are impacted by factors such as weather, economic growth or recession, technological change, EE, levels of Direct Access ("DA") and CCA participation, and distributed generation. PG&E generates a distribution of the bundled retail sales for each year using a model that simulates thousands of possible bundled load scenarios. Each scenario is based on regression models for load in each end use sector as a function of weather and economic conditions with consideration of future policy impacts on EE, EVs, and distributed generation.

As load loss due to DA is currently capped by California statute and cannot be expanded without additional legislation, PG&E is not forecasting increases in DA. Load loss due to CCA departure is modeled in two categories: (1) existing CCAs that have already departed or will depart and serve load by 2019; and (2) potential CCAs that have expressed interest in forming based on publicly available information. For existing CCAs, PG&E follows a meet and confer process to communicate with CCAs regarding their load forecasts. PG&E receives year-ahead load, peak demand, and customer forecasts from the CCAs, and grows these forecasts using PG&E's forecasted total system load growth rate, which accounts for economic/demographic factors, weather, and growth of DER technologies such as solar PV, EE. For potential CCAs, PG&E has developed a stochastic (probabilistic) approach to forecast CCA load departure. This model uses publicly available information—including feasibility studies, implementation plans, board meetings, and news articles—to assign probabilities to all communities considering CCA formation. Similar probabilities are applied to communities with the same CCA maturity levels. The model uses 2016 annual energy load as the benchmark, and PG&E applies system load growth percentages to approximate future load growth or decline. Appendix C.1 lists the resulting simulated retail sales and summary statistics for the period 2018-2030. Appendix C.5 shows the resulting simulated RPS target when accounting for the retail sales uncertainty for the period 2018-2030.

7.2.2. RPS Generation Variability

Based on analysis of historical hydro generation data from 1985-2012, wind generation data from 1985-2011, and generation data from solar and other technologies where available, PG&E estimated a historical annual variability measured by the coefficient of variation of each resource type. [redacted] Due to significant variability in annual precipitation, small hydro demonstrates the largest annual variability (coefficient of variation of [redacted]). The remaining resource types range in annual variability from [redacted] for biomass and geothermal, [redacted] for solar PV and solar thermal to [redacted] for wind. Collectively, technology diversity helps to reduce the overall variation, because variability around the mean is uncorrelated among technologies. Appendix C.3 lists the resulting simulated generation and summary statistics for the period 2018-2030.

To better understand the wide range of variability of the above risks and thus, the need for a stochastic model to optimize PG&E's procurement volumes,

Appendix C.4 combines the Project Failure and RPS Generation Variability factors into a "total deliveries" probability distribution, and shows how these variables interact.

7.2.3. Curtailment

The stochastic model also estimates the potential for RPS curtailment. Curtailment can result from either buyer-ordered (economic), CAISO-ordered or PTO-ordered curtailment (the latter two driven by system stability issues, not economics). Curtailment forecasts ramp from a historical level of [redacted].[44] These modeling assumptions will not necessarily reflect the actual number of curtailment hours, but are helpful in terms of considering the impact of curtailment on long-term RPS planning and compliance. Please see Section 12 for more information regarding curtailment.

7.2.4. Project Failure Variability

To model the project failure variability inherent in project development, PG&E assumes that project viability for a yet-to-be-built project is a function of the number of years until its contract start date. That is, a new project scheduled to commence deliveries to PG&E next year is considered more likely to be successful than a project scheduled to begin deliveries at a much later date. The underlying assumption is that both PG&E and the counterparty know more about a project's likelihood of success the closer the project is to its initial delivery date, and the counterparty may seek to amend or terminate a non-viable project before it breaches the PPA. Working from this assumption, PG&E assigns a probability of project success for new, yet-to-be-built projects equal to [redacted]. For example, a project scheduled to come online in five years or more is

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44 [redacted]

assumed to have a [redacted] percent chance of success. This success rate is based on experience and is reflective of higher project development success rates of PG&E's RPS portfolio in more recent years.

Although PG&E's current existing portfolio of projects may have higher rates of success, the actual success rate for projects in the long-term may be higher or lower. Appendix C.2 lists PG&E's simulated failure rate and summary statistics for the period 2017-2030.

7.2.5. Comparison of Model Assumptions

Table 7-3 below shows a comparison of how PG&E's deterministic and stochastic models each handle uncertainty with regard to retail sales, project failure, RPS generation, and curtailment. Section 8 provides a more detailed summary of the results from PG&E's deterministic and stochastic modeling approaches.

TABLE 7-3
COMPARISON OF UNCERTAINTY ASSUMPTIONS
BETWEEN PG&E'S DETERMINISTIC AND STOCHASTIC MODELS

Uncertainty[(a)]	Deterministic Model	Stochastic Model
1) Retail Sales Variability	Uses most recent PG&E bundled retail sales forecast for next 5 years and 2014 Long-Term Procurement Plan ("LTPP") for later years (Appendix A.1); Uses most recent PG&E bundled retail sales forecast for all years (Appendix A.2).	Distribution based on most recent (2017) PG&E bundled retail sales forecast.
2) Project Failure Variability	Only turns "off" projects with high likelihood of failure per criteria. "On" projects assumed to deliver at Contract Quantity.	Uses [redacted] to model a success rate for all "on" yet-to-be-built projects in the deterministic model. Thus, for a project scheduled to come online in 5 years, the project success rate is [redacted]. This success rate is based on PG&E's experience that the further ahead in the future a project is scheduled to come online, the lower the likelihood of project success.
3) RPS Generation Variability	Non-QF projects executed post-2002, 100% of contracted volumes. For non-hydro QFs, typically based on an average of the three most recent calendar year deliveries. Hydro QFs, UOG and ID&WA generation projections are updated to reflect the most recent hydro forecast.	Hydro: [redacted] annual variation Wind: [redacted] annual variation Solar: [redacted] annual variation Biomass and Geothermal: [redacted] annual variation
4) Curtailment	None	Curtailment is modeled as increasing between the following data points: [redacted] in 2017 [redacted] in 2020 [redacted] in 2024 [redacted] in 2030

(a) These modeling assumptions will not necessarily align with the future actual sales, project failure rates, RPS generation, and curtailment hours, but are helpful in terms of considering the impact of uncertainty on long-term RPS planning and compliance.

7.3. How Deterministic Approach Is Modeled

The deterministic model is a snapshot in time of PG&E's current and forecasted RPS position. The deterministic model relies on currently available generation data for executed online and in development RPS projects as well as PG&E's most recent bundled retail sales forecast. The results from the deterministic model determine PG&E's "physical net short," which represents the best current point-estimate forecast of PG&E's RPS position today. The deterministic model should not be seen as a static target because the inputs are updated as new information is received.

7.4. How Stochastic Approach Is Modeled

The stochastic model adds rigor to the risk-adjustment embedded in the deterministic model—using Monte Carlo simulation—and optimizes its results to achieve the lowest cost possible given a specified risk of non-compliance and the stochastic model's constraints.

The methodology for the stochastic model is as follows:

1) Create an optimization problem by establishing the (a) objectives; (b) inputs; and (c) constraints of the model:
   - (a) The objective is to minimize procurement cost.
   - (b) The inputs are a range of potential incremental RPS-eligible deliveries (new and re-contracted volumes)[45] in each year of the [redacted] timeframe. The potential incremental procurement is restricted to a range of no less than zero and no more than [redacted] annually.
   - (c) The constraints are: (1) to keep PG&E's risk of non-compliance to less than [redacted], less than [redacted], less than [redacted]; and (2) to restrict PG&E's Bank over time to the size necessary to meet compliance objectives within the specified risk threshold.

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45 Although the physical net short calculations do not include any assumptions related to the re-contracting of expiring RPS-eligible contracts, this modeling approach assumes re-contracting will be considered in the future side-by-side with procurement of other new resources.

2) The stochastic model then solves the optimization problem by examining thousands of combinations of procurement need in each year. For each of these combinations, the model runs hundreds of iterations as part of its Monte Carlo simulation of uncertainty for each of the risk factors in the stochastic model to test if the constraints are met. If the solution for that combination of inputs fits within the given constraints, it is a valid outcome.
3) For each valid outcome, the mean Net Present Value ("NPV") cost of meeting that procurement need is calculated based on PG&E's RPS forward price curve.
4) Finally, the model sorts the NPV of the potential procurement outcomes from smallest to largest, thus showing the optimal RPS-eligible deliveries needed in the years [redacted] to ensure compliance based on the modeled assumptions.

The modeled solution becomes a critical input into PG&E's overall RPS optimization strategy, but the outputs are subject to further analysis based upon best professional judgment to determine whether factors outside the model could lead to better outcomes. For example, the model does not allow for price arbitrage through sales of RPS generation in the near-term and additional incremental procurement in the long-term. Nor does the model consider the opposite strategy of advance procurement of RPS-eligible products in 2018 for purposes of reselling those products in the future at a profit. As a general matter, PG&E does not approach RPS procurement and compliance as a speculative enterprise and so has not modeled or otherwise proposed such strategies in this 2018 RPS Plan.

7.5. Incorporation of the Above Risks in the Two Models Informs Procurement Need and Sales Opportunities

Incorporating inputs from the deterministic model, the stochastic model provides results that lead to a forecasted procurement need or SONS, expected Bank usage and thus an anticipated Bank size, for each compliance period. The SONS for the existing RPS targets are shown in Row La of PG&E's Alternate RNS in Appendix A.2.

The results of both the deterministic and stochastic models are discussed further in Section 8 and minimum margin of procurement is addressed in Section 9.

8. **Quantitative Information**

As discussed in Section 7, PG&E's objectives for this RPS Plan are to both achieve and maintain RPS compliance and to minimize customer cost within an acceptable level of risk. To do that, PG&E uses both deterministic and stochastic models. This section provides details on the results of both models and references RNS tables provided in Appendix A. Appendix A.1 presents the RNS in the form required by the ALJ's Ruling on RNS issued May 21, 2014 in R.11-05-005 ("ALJ RNS Ruling") and includes results from PG&E's deterministic model only, while Appendix A.2 is a modified version of Appendix A.1 to present results from both PG&E's deterministic and stochastic models. These modifications to the table are necessary in order for PG&E to adequately show its results from its stochastic optimization.

This section includes a discussion of PG&E's forecast of its Bank size and PG&E's analysis of the minimum bank needed.

8.1. Deterministic Model Results

Results from the deterministic model under a 60 percent by 2030 RPS target and 60 percent RPS annually thereafter are shown as the physical net short in Row Ga of Appendices A.1 and A.2. Appendix A.1 provides a physical net short calculation using PG&E's March 2018 internal Bundled Retail Sales Forecast for years 2018-2022 and the LTPP sales forecast for 2023-2036,[46] while Appendix A.2 relies exclusively on PG&E's March 2018 internal Bundled Retail Sales Forecast. Following the methodology described in Section 7.1, PG&E currently estimates a long-term volumetric success rate of 100 percent for its portfolio of executed-but-not-operational projects. The annual forecast failure rate used to determine the long-term volumetric success rate is shown in Row Fbb of Appendix A.2. This success rate is a snapshot in time and is also impacted by current conditions in the renewable energy industry, discussed in more detail in Section 6, as well as project-specific conditions. In addition to the current long-term volumetric success rate, Rows Ga and Gb of Appendix A.2 depict PG&E's

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46 Bundled sales forecast used for 2023-2036 is from the Conforming Case in PG&E's 2018 LSE IRP filed for the 2017-2018 IRP Cycle.

expected compliance position using the current expected need scenario before application of the Bank.

8.2. Stochastic Model Results

This subsection describes the results from the stochastic model and the SONS calculation for the 60 percent RPS by 2030 target, and 60 percent RPS annually thereafter. Because PG&E uses its stochastic model and internal Bundled Retail Sales Forecast to inform its RPS procurement, PG&E has created an Alternate RNS in Appendix A.2 for the 60 percent RPS target. Appendix A.1 provides an incomplete representation of PG&E's optimized net short, as the formulas embedded in the RNS form required by the ALJ RNS Ruling do not enable PG&E to capture its stochastic modeling inputs and outputs. In Appendix A.2, two additional rows have been added. Rows Gd and Ge show the stochastically-adjusted net short, which incorporates the risks and uncertainties addressed in the stochastic model. This is prior to any applications of the Bank, but includes additional procurement needed for maintaining an optimized Bank size. Additionally, PG&E has modified the calculations in Rows La and Lb in order to more accurately represent PG&E's SONS.

Under the existing RPS targets, PG&E is well-positioned to meet its compliance period requirements through the fifth (2025-2027) compliance period. As shown in Row Lb of Appendix A.2, the stochastic model shows a third compliance period RPS position of [redacted], a fourth compliance period RPS position of [redacted], a fifth compliance period RPS position of [redacted], and a sixth compliance period RPS position of [redacted]. Appendix A.2 also shows a physical net short of approximately [redacted] beginning in 2026 (Row Ib plus Row Gd).

For both tables, Row Lb includes both PG&E's executed and generic RPS sales volumes shown in Rows Fd and Ib, respectively, and equates to 2,069 GWh per year of total RPS sales except for 2019.[47] The annual RPS sales volume forecast assumption

47 Total forecasted RPS sales in 2019 equals 4,729 GWh based on executed sale agreements through August 31, 2018.

is based on the actual RPS sales completed in 2017 and is included for RPS position planning purposes. Based on the sales framework approved in the 2017 RPS Plan, these volumes could potentially exceed [redacted] in any given year if [redacted]. Under the updated RPS Sales Framework proposed in Appendix G, annual sales volumes could be even greater depending on [redacted]. In the event that the total RPS generation less RPS sales falls below the RPS Compliance requirement in any given year, PG&E would still meet its RPS Compliance requirement through the use of previously accumulated RPS bank (see Row J in Appendix A.2).

8.2.1. Stochastically-Optimized Net Short to Meet Non-Compliance Risk Target

To evaluate possible procurement strategies, PG&E selected the following non-compliance risk targets for each future CP: [redacted]

Figure 8-1 shows the model's forecasted procurement need and resulting Bank usage under the 60 percent RPS by 2030 target and 60 percent RPS annually thereafter. Under this projection, a portion of the Bank is used to meet PG&E's compliance need beginning in 2026, the first year showing a stochastically-adjusted net short, and continuing throughout the decade, while reserving a portion of the Bank to be maintained as VMOP to manage risks discussed in Section 7. Appendix A.2 provides the detailed results. Annual forecasted Bank usage is shown as the sum of Rows Gd and Ib of this Appendix. After accounting for Bank usage, the first year of incremental procurement need is forecasted as after 2033. Should PG&E engage in additional RPS sales, this may result in an earlier procurement need year and its position will be updated in subsequent RPS Plans.

FIGURE 8-1
CONFIDENTIAL
STOCHASTIC RESULTS: EXPECTED BANK USAGE AND STOCHASTICALLY-OPTIMIZED NET SHORT

[redacted]

Note: Net short and bank usage values have been rounded to the nearest 100 GWh.

Because the stochastic model inputs change over time, these estimates should be seen as a snapshot in time rather than a static target and the procurement targets will be re-assessed as part of future RPS Plans.

8.2.2. Bank Size Forecasts and Results

Figure 8-2 shows PG&E’s current and forecasted cumulative Bank from the first compliance period through 2033. PG&E’s total Bank size as of the end of the second compliance period was approximately 12,800 GWh. The stochastic model’s results currently project PG&E’s Bank size to increase in the second through fifth compliance periods and gradually decrease over time to approximately [redacted] (as shown in Figure 8-2, as well as in Appendix A.2, Row J). As stated in Section 8.2 above, the forecasted 2033 Bank total assumes 2,069 GWh per year of RPS sales. Given the expected size of the Bank in 2030, PG&E is proposing a change to its RPS sales framework in order to increase the volumes available to sell during the period covered by this 2018 RPS Plan (see Section 4).

FIGURE 8-2
CONFIDENTIAL
STOCHASTIC RESULTS: EXPECTED CUMULATIVE BANK

[redacted]

Note 1: Bank values in CP1 and CP2 are based on the total 'Excess Procurement Bank' in PG&E's RPS Compliance Report.

Note 2: Bank values in CP3 and beyond have been rounded to the nearest 100 GWh.

There is a trade-off between non-compliance risk and Bank size. A larger Bank size decreases non-compliance risk. However, a larger Bank size may also increase procurement costs. Higher risk scenarios would result in a lower Bank size and, as discussed above, would increase PG&E's probability of being in a position in which PG&E might need to make unplanned purchases to comply with its RPS requirement. In that situation, PG&E might not be able to avoid higher procurement costs due to the potential for upward pressure on prices caused by the need for unplanned purchases. [redacted]

8.2.3. Minimum Bank Size

PG&E performed a simulation of variability in PG&E's future generation and RPS compliance targets over [redacted] years—i.e., the amount of the RPS generation ("delivery") net of RPS compliance targets ("target")—and found that a Bank size of at least [redacted] GWh is the minimum Bank necessary to maintain a cumulative non-compliance risk of no greater than [redacted].[48] The difference between delivery and target can be thought of as the potential "need" (if negative) or "surplus" (if positive) that PG&E has in any one year.

Figure 8-3 shows this distribution based on the deterministic procurement necessary to meet the expected RPS targets with expected generation during [redacted].

Based on current model assumptions and inputs, Figure 8-3 shows that approximately [redacted] of the time, PG&E would have a greater than [redacted] GWh deficit in meeting compliance for [redacted]. Thus, PG&E must maintain a Bank size higher than this amount to limit the risk of non-compliance to an acceptable level.[49]

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48 [redacted]

49 See Footnote 25.

FIGURE 8-3
CONFIDENTIAL
DISTRIBUTION OF DELIVERY MINUS TARGET FROM 2026 THROUGH 2030
UNDER A 60 PERCENT RPS TARGET

[redacted]

As stated in Section 8.2.2, the stochastic model's results show PG&E's forecasted [redacted]. PG&E's strategy is to maintain an adequate Bank in order to avoid the need to procure extremely large volumes in any single year to meet compliance needs.

Because the model inputs change over time, estimates of the Bank size resulting from the implementation of the procurement plan will also change. In practice, the actual outcome will more likely be a mix of factors both detracting from and contributing to meeting the target, which is what the probability distribution in Figure 8-3 illustrates.

8.3. Implications for Future Procurement

PG&E plans to continually refine both its deterministic and stochastic models, thus the procurement strategy outlined above is applicable to this 2018 RPS Plan only. In future years, PG&E's procurement strategy will likely change, based on updates to the data and algorithms in both models. Additionally, PG&E will continue to assess the value to its customers of sales. PG&E will update its physical RNS in future RPS Plans if it executes any such sale agreements.

9. **Margin of Procurement**

When analyzing its margin of procurement, PG&E considers two key components: (1) a statutory minimum margin of procurement to address some anticipated project failure or delay, for both existing projects and projects under contract but not yet online, that is accounted for in PG&E's deterministic model; and (2) a VMOP, which aims to mitigate the additional risks and uncertainties that are accounted for in PG&E's stochastic model. Specifically, PG&E's VMOP intends to: (a) mitigate risks associated with short-term variability in load; (b) protect against project failure or delay exceeding forecasts; and (c) manage variability from RPS resource generation. In so doing, PG&E's VMOP helps to eliminate the need at this time to procure long-term contracts above the 60 percent RPS target by creating a buffer that enables PG&E to manage the year-to-year variability that result from risks (a)-(c). This section discusses both of these components and how each is incorporated into PG&E's quantitative analysis of its RPS need.

9.1. Statutory Minimum Margin of Procurement

The RPS statute requires the Commission to adopt an "appropriate minimum margin of procurement above the minimum procurement level necessary to comply with the [RPS] to mitigate the risk that renewable projects planned or under contract are delayed or canceled."[50] PG&E's reasonableness in incorporating this statutory minimum margin of procurement into its RPS procurement strategy is one of the factors the Commission must consider if PG&E were to seek a waiver of RPS enforcement because conditions beyond PG&E's control prevented compliance.[51]

As described in more detail in Section 7, PG&E has developed its risk-adjusted RPS forecasts using a deterministic model that: (1) excludes volumes from contracts at risk of failure from PG&E's forecast of future deliveries; and (2) adjusts expected commencement of deliveries from contracts whose volumes are included in the model

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50 Cal. Pub. Util. Code § 399.13(a)(4)(D).

51 *Id.*, § 399.15(b)(5)(B)(iii).

(so long as deliveries commence within the allowed delay provisions in the contract). PG&E considers this deterministic result to be its current statutory margin of procurement.[52] However, as discussed in Sections 7 and 8, these results are variable and subject to change, and thus PG&E does not consider this statutory margin of procurement to sufficiently account for all of the risks and uncertainties that can cause substantial variation in PG&E's portfolio. To better account for these risks and uncertainties, PG&E uses its stochastic model to assess a VMOP, as described further below.

9.2. Voluntary Margin of Procurement

The RPS statute provides that in order to meet its compliance goals, an IOU may voluntarily propose a margin of procurement above the statutory minimum margin of procurement.[53] As discussed further in Sections 7 and 8, PG&E plans to use a portion of its Bank as a VMOP to manage additional risks and uncertainties accounted for in the stochastic model.

While PG&E's current optimization strategy projects the use of a portion of PG&E's projected Bank to meet compliance requirements in 2028 and beyond, PG&E believes it would be imprudent to use its entire projected Bank toward meeting its RPS compliance, rather than to cover unexpected demand and supply variability and project failure or delay exceeding forecasts from projects not yet under contract. When used as VMOP, holding a minimum Bank will reduce non-compliance risk, helping to avoid long-term over-compliance above the existing RPS targets and thus reducing long-term costs of the RPS Program. Since the model inputs change over time, estimates of the Bank and VMOP are not a static target and will change, so these estimates should be

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52 In the past PG&E has seen higher failure rates from its overall portfolio of executed-but-not-operational RPS contracts. However, as the renewables market has evolved—and projects are proposed to PG&E at more advanced stages of development—PG&E has observed a decrease in the expected failure rate of its overall portfolio. The more recent projects added to PG&E's portfolio appear to be significantly more viable than some of the early projects in the RPS Program, resulting in lower current projections of project failure than have been discussed in past policy forums.

53 Cal. Pub. Util. Code § 399.13(a)(4)(D).

seen as a snapshot in time. Additional discussion on the need for and use of the Bank and VMOP are included in Sections 7 and 8.

Additionally, as a portion of the Bank will be used as VMOP, PG&E will continue to reflect zero volumes in Row D of its RNS tables, consistent with how it has displayed the VMOP in past RNS tables.

10. **Bid Selection Protocol**

As described in Sections 3 and 8, PG&E is well positioned to meet its RPS targets until after 2033. As a result, PG&E proposes to not hold a 2019 RPS procurement solicitation. PG&E will continue to procure RPS-eligible resources in 2018 and 2019 through other Commission-mandated programs, such as the BioMAT and PV RAM programs. PG&E will seek permission from the Commission to procure any renewable energy amounts during the time period covered by the 2018 RPS Plan, except for RPS amounts that are separately mandated. Thus, PG&E is not including in the 2018 RPS Plan a solicitation protocol for procuring additional RPS resources.

Although PG&E is not planning for a RPS Solicitation, PG&E recognizes that the most recent detailed description of its least-cost, best-fit ("LCBF") methodology, including the NMV and PAV methodologies, included in PG&E's final 2014 RPS RFO Protocol (Attachment K) has continued to be used as a reference for procurement valuation for mandated programs and as a reference for RPS energy sales. The PAV adjustments in the 2014 protocol represent the value of procurement to PG&E's portfolio. However, the value of additional RPS procurement when PG&E's portfolio is very long or very short may be different than the value of RPS sales under those conditions. Accordingly, as part of this 2018 RPS Plan, PG&E is providing an update to the LCBF methodology approved in its 2014 RPS planning cycle to better reflect current market and portfolio conditions. PG&E's updates to the quantitative LCBF Protocol include: (1) elimination of the energy firmness PAV adder; (2) elimination of the curtailment hours PAV adder; and (3) adjustment of the RPS portfolio position adder to accommodate RPS sales. PG&E is also eliminating the quantitative PAV adjustments for SP15 energy and capacity, and instead adds PG&E's preference for projects located within its service territory as a qualitative adjustment. Finally, PG&E has streamlined the discussion of qualitative factors and eliminated the references to the CPUC Project Viability Calculator. The revised version of PG&E's detailed explanation of its LCBF methodology is included as Appendix H to this 2018 RPS Plan. A redline showing this revised version of the LCBF methodology against the last Commission-approved version (from PG&E's 2014 RPS Plan) is provided for convenience at Appendix I to this 2018 RPS Plan.

PG&E has included in Section 4, above, a description of the framework that PG&E proposes to use to assess whether to hold or sell RPS volumes. The framework itself is included in Confidential Appendix G. The Commission has approved a similar framework in the 2016 and 2017 RPS Plans. As described in Section 4, above, PG&E targets issuing three, with a minimum of two, solicitations in 2019 for short-term (meaning contracts of five years or less in duration) sales of bundled RPS volumes using the framework. PG&E ~~will~~may also seek to negotiate longer-term sales of RPS products~~.~~ after Phase 2 of the PCIA OIR is resolved, depending on the outcome in that proceeding. PG&E has included a solicitation protocol and pro~~-~~ forma sales agreement as Appendix~~-~~ F.3 to this 2018 RPS Plan. The pro forma sales agreement is based on the EEI Master Agreement and is consistent with the form agreement that PG&E used in its 2018 RPS Sales Solicitation. The protocol represents a streamlined approach to selling RPS energy, with the primary selection criterion being price. The protocol and form of sales agreement incorporate lessons learned from the 2018 RPS Sales Solicitation, as described in Sections 4 and 10.

PG&E anticipates that minimal negotiations will be needed with respect to the form sales agreement and proposes filing any executed sales agreements by a Tier 1 Advice Letter for Commission approval. This approach is consistent with the streamlined Tier 1 Advice Letter process authorized in D.14-11-042 for short-term sales agreements. In that decision, the Commission determined that a Tier 1 Advice Letter process could be utilized[54] as long as a utility has included a pro forma short-term contract as part of its approved RPS plan filing and the contract term is under five years. Streamlined processes for both RFO administration and Commission approval are required in order to allow for transactions to occur in 2019.

10.1. Proposed Time of Delivery Factors

PG&E historically set the Time of Delivery ("TOD") factors in its RPS procurement contracts based on expected (internally forecasted) hourly prices, load forecasts, and capacity values. PG&E periodically reviews the effectiveness of these factors, even in RPS planning cycles, like the current one, in which it is not proposing to conduct an RPS solicitation. This is because the TOD factors adopted in the RPS Plan are incorporated into the non-modifiable form contracts used for ongoing mandatory procurement programs and would be used in any future procurement that PG&E either proposes or is directed by the Commission to undertake.

In PG&E's review of the TOD factors for this 2018 RPS Plan, PG&E has determined that it is increasingly difficult to accurately forecast TOD preferences within even the next decade, let alone for the duration of a typical RPS PPA (e.g., 20 years), given California's quickly evolving energy mix, policies, and markets.

PG&E generally supports the efforts of the State to move toward dynamic pricing of both energy demand and energy supply. However, in the absence of having the flexibility to dynamically change the TOD factors in an executed PPA (at least on an annual basis) to adjust to the ongoing changes in the market, TOD factors in a long-term PPA are unlikely to reflect system need over the entire life of the PPA. In fact, changes in the State's net load over time may result in TOD factors incentivizing production under a PPA at times in which the PPA contributes to overgeneration problems, rather than helps to solve them. On the other hand, inserting contractual provisions that allow PG&E to alter TOD factors on a regular basis to match system

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54 D.14-11-042, pp. 74-78, and implemented in PG&E's approved 2014 RPS Plan.

need could make the PPA difficult or impossible to finance since there would be no certainty around the revenue stream generated by the project.

Given the reasons outlined above, PG&E proposes to eliminate TOD factors for any new RPS procurement contracts that may be executed in the future, including in new contracts to be executed in existing mandatory procurement programs, such as BioMAT. However, pursuant to D.19-02-007, PG&E will calculate TODs for informational purposes only, in order to communicate to developers when energy deliveries might be more valuable to the system and allow developers to respond with optimized project designs and bids.[55] PG&E's proposed informational-only TOD factors will be served on the R.18-07-003 service list within 90 days of issuance of D.19 02-007.[56]

10.2. Workforce Development

SB 2 (1X) added a requirement that the LCBF criteria for ranking and selecting RPS resources shall include "the employment growth associated with the construction and operation of eligible renewable energy resources."[57] The 2018 RPS Plan Ruling directs the IOUs to include a description of a proposed approach for assessing and differentiating the ability of different bids to contribute to employment growth during the construction and operational phases of the project.[58]

PG&E does not expect to procure any RPS resources beyond mandated programs, so there will be limited opportunity to apply a new selection criterion this year. However, PG&E's LCBF methodology does include a qualitative assessment of the extent to which the proposed development supports RPS goals. It is based on information provided by the Seller and PG&E's assessment of that information. If PG&E were procuring RPS resources, it would require bidders to submit information on

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55 D.19-02-007, OP 16.

56 *Id.*, OP 17.

57 Cal. Pub. Util. Code § 393.13(a)(4)(A)(iv).

58 2018 RPS Plan Ruling, p. 14.

projected California employment growth during construction and operation. This would include number of hires, duration of hire, and indication of whether the bidder has entered into Project Labor Agreements or Maintenance Labor Agreements in California for the proposed project. This information was required from bidders in PG&E's 2014 RPS RFO.[59]

10.3. Disadvantaged Communities

SB 2 (1X) also added the requirement that preference shall be given "to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases."[60] The 2018 RPS Plan Ruling directs the IOUs to include a description of their methodology for preferring projects that provide those benefits.[61]

As explained above, PG&E does not expect to procure any RPS resources beyond mandated programs, so there will be limited opportunity to apply a new selection criterion this year. However, PG&E has included this component as part of its assessment of an offer's consistency with and contribution to California's goal for the RPS Program. PG&E's LCBF methodology includes a qualitative assessment of the extent to which the proposed development supports RPS goals is based on information provided by the Seller, and PG&E's assessment of that information.

If PG&E were procuring resources, it would expect to solicit information from participants similar to what was required in the 2014 RPS RFO.[62] PG&E asked participants to respond to the following questions on this topic:

> Is your facility located in a community afflicted with poverty or high unemployment or that suffers from high emission levels? If so, the Participant is encouraged to describe in its Offer, if applicable, how its proposed facility can provide the following benefits to adjacent communities:

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59 Appendix J2 to 2014 RPS RFO Protocol.

60 Cal. Pub. Util. Code § 399.13(a)(7).

61 2018 RPS Plan Ruling, p. 15.

62 Appendix J2 to 2014 RPS RFO Protocol.

- Projected hires from adjacent community (number and type of jobs),
- Duration of work (during construction and operation phases),
- Projected direct and indirect economic benefits to the local economy (i.e., payroll, taxes, services),
- Emissions reduction – Identify existing generation sources by fuel source within 6 miles of proposed facility; Will the proposed facility replace/supplant identified generation sources?
  - If “yes”, provide estimated reduction in air pollutants/toxics in the community over life of the project/contract due to the facility (when/how much MWh/year), and avoided emissions released into the community (within 6 miles of the project).
  - If “No”, why not?

10.4. 2018 RPS Sales – Lessons Learned

While PG&E has executed a limited number of agreements for the sale of RPS volumes from PG&E’s portfolio, PG&E’s second such solicitation (the “2018 RPS Sales Solicitation”) was issued in 2018. Upon completion of the 2018 RPS Sales Solicitation, PG&E surveyed market participants to solicit feedback on how to improve the process and to understand why certain market participants did not bid. In addition, PG&E received feedback from the Independent Evaluator assigned to monitor the solicitation and resulting negotiations.

As a result, PG&E has identified a number of best practices to incorporate for future solicitations. They include:

Desire for PCC Certainty

Counterparties consistently sought contract language certifying that the bundled RPS volumes to be sold and purchased would be deemed to be PCC 1 by the CPUC. PG&E agreed to represent that the resources used for the sale, if retired for compliance by PG&E, would be expected to meet the definition of PCC 1 as described in Pub. Util. Code Section 399.16(b)(1). However, PG&E was unable to provide the certification that buyers requested because any such determination is outside of PG&E’s control. The CPUC determines the applicable PCC category of RPS products used by retail sellers to meet RPS compliance requirements in a process that is independent from, and later in time from, the process to review and approve a contract executed by PG&E for the sale of RPS volumes. Given the request presented to PG&E, PG&E believes that it would facilitate the sale of bundled RPS volumes if the CPUC determined the PCC of the products as to the purchasing entity in connection with the Advice Letter approval process to review the sales agreement.

Product Term

In 2018, PG&E sought sales with energy deliveries in multiple years (2018 through 2022) rather than in a single year as it had previously solicited in 2017. Buyers were receptive to the extended term of energy deliveries in the 2018 RPS Sales Solicitation and conveyed their preference sales for multiple years rather than single years. In 2019, PG&E will continue to solicit sales with deliveries across multiple years.

Timing and Timeline of Solicitation

[redacted]

To address these concerns PG&E will conduct future solicitations in a very streamlined manner, and as described in Section 4, above, intends to target issuing three, with a minimum of two, solicitations during calendar year 2019. PG&E aims to issue its first 2019 RPS Sales Solicitation shortly after the 2018 RPS Plan has received final approval from the CPUC.

Execution Process

In future Sales Solicitations, PG&E will identify in advance which areas of the sales agreement are eligible to be discussed. Using the standardized form of agreement developed in 2017, PG&E engaged in limited discussions with buyers in 2018. [redacted] As a result, PG&E expects discussions with buyers on the sales agreement to be minimal in 2019 to streamline the execution process.

11. **Consideration of Price Adjustment Mechanisms**

The 2018 RPS Plan Ruling requires each IOU to "describe how price adjustments (e.g., index to key components, index to Consumer Price Index ("CPI"), price adjustments based on exceeding transmission or other cost caps, etc.) will be considered and potentially incorporated into contracts for RPS-eligible projects with online dates occurring more than 24 months after the contract execution date."[63]

In this 2018 RPS Plan, PG&E is proposing to not hold an RPS solicitation in 2018. If PG&E was negotiating PPAs for additional procurement, PG&E might consider a non-standard PPA with pricing terms that are indexed, but indexed pricing should be the exception rather than the rule. Customers could benefit from pricing indexed to the cost of key components, such as solar panels or wind turbines, if those prices decrease in the future. Conversely, customers would also face the risk that they will pay more for the energy should prices of those components increase. Asking customers to accept this pricing risk reduces the rate stability that the legislature has found is a benefit of the RPS Program.[64] In order to maximize the RPS Program's benefits to customers, cost risk should generally be borne by developers.

Additionally, indexing greatly complicates offer selection, negotiation and approval. It may be challenging to incorporate contract price adjustment mechanisms into PPA negotiations when there is no clear, well-established and well-defined agreed-upon index. There are many components to the cost of construction of a renewable project, and indexes tied to these various components may move in different directions. The increased complexity inherent in such negotiations is counter to the

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63 2018 RPS Plan Ruling, p. 15.

64 Cal. Pub. Util. Code § 399.11(b)(5).

Commission’s expressed desire to standardize and simplify RPS solicitation processes.[65]

Moreover, Sellers may not have as much incentive to reduce costs if certain cost components are indexed. For example, a price adjustment based on the cost of solar panels (i.e., if panel costs are higher than expected, the price may adjust upward) may not create enough incentive to minimize those costs. This would create a further level of complexity in contract administration and regulatory oversight.

Finally, PG&E does not recommend that PPA prices be linked to the CPI. The CPI is completely unrelated to the cost of the renewable resource, and is instead linked to increases in prices of oil and natural gas, food, medical care and housing. Indexing prices to unrelated commodities heightens the derivative and speculative character of these types of transactions.

12. **Economic Curtailment**

In D.14-11-042, the Commission directed that the IOUs describe in future RPS Plans how “expected economic curtailment affects their RPS procurement.”[66] In addition, the Commission directed the IOUs to report on observations and issues related to economic curtailment, including reporting to the PRG.[67] In July 2018, PG&E made a presentation to its PRG on economic curtailment. This section provides information to the Commission and parties regarding PG&E’s observations and issues related to economic curtailment both for the market generally, and PG&E’s specific scheduling practices for its RPS-eligible resources.

With regard to market conditions generally, the frequency of negative price periods in the first part of 2018 has decreased in the Real-Time Markets (“RTM”) for the PG&E Default Load Aggregation Point (DLAP) and for the North of Path 15 Hub (“NP15 Hub”) as compared to previous years. During January through April 2018, negative

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65 D.11-04-030, pp. 33-34.

66 D.14-11-042, p. 45.

67 *Id*., pp. 42-43.

price intervals in the CAISO Five Minute Market for the PG&E DLAP occurred in approximately 4.2 percent of the 5-minute intervals, compared to approximately 13.5 percent during the same period in 2017 and 7.6 percent during the same period in 2016. Trends are similar for NP 15 and ZP 26. The specific occurrences of negative price periods and overgeneration events are largely unpredictable; [redacted] to minimize exposure to negative pricing.

[redacted]

[redacted][68] [redacted] PG&E submits bids for these resources based on the resource's opportunity costs, subject to contractual, regulatory, and operational constraints. [redacted] PG&E provided more detail concerning its RPS bidding strategy in its Bundled Procurement Plan[69] which was approved by the Commission in D.15-10-031.

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68 [redacted]

69 See PG&E, 2014 Bundled Procurement Plan, Appendix K (Bidding and Scheduling Protocol).

[redacted][70] [redacted][71] While direct benefits of economic bidding include avoided costs and CAISO market payments associated with negative prices, there can be other important benefits, including potentially avoiding the cost impacts across the rest of PG&E's portfolio due to extreme negative price periods, and also CAISO system reliability by helping to mitigate the occurrences, duration, or severity of negative price periods or overgeneration events. The overall trends in both the frequency and magnitude of negative prices in recent years suggests that the CAISO is able to generally balance supply and demand using economic curtailment rather than administratively curtailing generation.

Regarding longer-term RPS planning and compliance, in order to ensure that RPS procurement need forecasts account for curtailment, PG&E adds curtailment as a risk adjustment within the stochastic model. For a discussion of forecasted curtailment levels please see Section 7.2.3. PG&E will continue to observe curtailment events and update its curtailment assumptions as needed.

Finally, PG&E continues to review its existing portfolio of RPS contracts to determine if additional economic curtailment flexibility may be available to help address the increase in oversupply events.

13. Cost Quantification

This section summarizes results from actual and forecasted RPS generation costs (including incremental rate impacts), shows potential increased costs from

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70 Net load refers to normal demand for electricity minus the contribution from solar and wind generation.

71 [redacted]

mandated programs, and identifies the need for a clear cost containment mechanism to address RPS Program costs. Tables 1 through 4 in Appendix B provide an annual summary of PG&E's actual and forecasted RPS costs and Page 1 of Appendix B outlines the methodology for calculating the costs and generation.

13.1. RPS Cost Impacts

Appendix B quantifies the cost of RPS-eligible procurement—both historical (2003-2017) and forecast (2018-2030). From 2003 to 2017, PG&E's annual RPS-eligible procurement and generation costs have continued to increase. Compared to an annual cost of $523 million in 2003, PG&E incurred more than $2.4 billion in procurement costs for RPS-eligible resources in 2017.

RPS Program costs impact customers' bills. Incremental rate impacts, defined as the annual total cost from RPS-eligible procurement and generation divided by bundled retail sales, effectively serve as an estimate of a system average bundled rate for RPS-eligible procurement and generation.[72] While this formula does not provide an estimate of the renewable "above-market premium" that customers pay relative to a non-RPS-eligible power alternative, the annual rate impact results in Tables 1 and 2 of Appendix B illustrate the potential rate of growth in RPS costs and the impact this growth will have on average rates, all other factors being equal. Annual rate impact of the RPS Program increased from 0.7¢/kWh in 2003 to an estimated 4.8¢/kWh in 2018, meaning the average rate impact from RPS-eligible procurement has increased by nearly seven-fold in approximately 15 years. As load departure increased and accelerated in recent years, flaws in the PCIA methodology have caused bundled customers to bear a disproportionately high share of this rate impact. This growth rate is projected to continue increasing through 2021, as the average rate impact is forecasted to increase to 6.8¢/kWh. In addition to the increasing RPS costs and incremental rate impacts on customer costs resulting from the direct procurement of the

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72 These rates do not reflect allocated costs to departed load (e.g., DA and Community Choice Aggregation customers). Without taking into account the allocation credit the illustrative rate impacts are higher than the forecasted bundled rate impact.

renewable resources, there are incremental indirect transmission and integration costs associated with that procurement.

13.2. Cost Impacts Due to Mandated Programs

The cost impacts of mandated procurement programs that focus on particular technologies or project size have comprised an increasing share of PG&E's incremental procurement in recent years, to the extent that incremental procurement is now entirely mandated by Commission programs.

In general, mandated procurement programs do not optimize RPS costs for customers because they restrict flexibility and optionality to achieve emissions reductions by mandating procurement through a less efficient and more costly manner. For instance, research shows that market-based mechanisms, like cap-and-trade, that allow multiple and flexible emissions reduction options, have lower costs than mandatory mechanisms like technology targets that allow only a subset of those options.[73] Studies have also shown that renewable electricity mandates increase prices and costs,[74] and procurement mandates within California's RPS decrease efficiency in the same way.

Mandates restrict the choices to meet the RPS targets, removing potentially less expensive options from the market. This can increase prices in two ways: first, by disqualifying those less expensive participants; and second, by creating a less robust

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73 *See*, *e.g.*, Palmer and Burtraw, "Cost-Effectiveness of Renewable Electricity Policies" (2005) (available at http://www.rff.org/Documents/RFF-DP-05-01.pdf); Sergey Paltsev et al., "The Cost of Climate Policy in the U.S." (2009) (available at http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.177.6721&rep=rep1&type=pdf); Palmer, Sweeney, and Allaire, "Modeling Policies to Promote Renewable and Low-Carbon Sources of Electricity" (2010) (available at http://www.rff.org/files/sharepoint/WorkImages/Download/RFF-BCK-Palmeretal%20-LowCarbonElectricity-REV.pdf).

74 *See*, *e.g.*, Institute for Energy Research, "Energy Regulation in the States: A Wake-up Call"; Manhattan Institute, "The High Cost of Renewable Electricity Mandates" (available at http://www.manhattan-institute.org/html/eper_10.htm).

market for participants to compete.[75] PG&E's customers also pay incremental costs due to the administrative costs associated with managing separate solicitations for mandated resources. In addition, smaller project sizes for mandated programs create a greater number of projects which, in turn, affect interconnection and transmission availability and costs. Finally, mandated programs do not enable PG&E to procure the technology, size, vintage, location and other attributes that would best fit its portfolio. As a result, PG&E's costs for managing its total generation and portfolio increase. For these reasons, PG&E supports a technology neutral procurement process, in which all technologies can compete to demonstrate which projects provide the best value to customers at the lowest cost.

14. Important Changes to Plans Noted

This Section describes the most significant changes between PG&E's Final 2017 RPS Plan and its Draft 2018 RPS Plan as filed on August 20, 2018. A complete redline of the Draft 2018 RPS Plan against PG&E's Final 2017 RPS Plan is included as Appendix I of the Draft 2018 RPS Plan originally filed on August 20, 2018. The table below provides a list of key differences between the two RPS Plans:

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[75] *See*, Fischer and Preonas, "Combining Policies for Renewable Energy: Is the Whole Less Than the Sum of Its Parts?" (2010) (available at http://www.rff.org/Documents/Fischer_Preonas_IRERE_2010.pdf).

TABLE 14-1
SUMMARY OF CHANGES

Reference	Area of Change	Summary of Change
Draft Plan Document and Appendices	Expiring Contracts, Imperial Valley, Project Development Status Update, Expiring Contracts	Removed Sections
Section 10.1	Proposed TOD Factors	Eliminated for any new RPS contracts
Section 10.4	2018 RPS Sales - Lessons Learned	Updated based on 2018 RPS Sales lessons learned
Section 4 and Appendix G	Sales Framework	Updated based on 2017 RPS Plan lessons learned
Appendix H	Least-Cost, Best-Fit Methodology	Updates to reflect current market conditions

15. Safety Considerations

PG&E is committed to providing safe utility (electric and gas) service to its customers. As part of this commitment, PG&E reviews its operations, including energy procurement, to identify and mitigate, to the extent possible, potential safety risks to the public and PG&E's workforce and its contractors. Because PG&E's role in ensuring the safe construction and operation of RPS-eligible generation facilities depends upon whether PG&E is the owner of the generation or is simply the contractual purchaser of RPS-eligible products (e.g., energy and RECs), this section is divided into separate discussions addressing each of these situations.

15.1. Development and Operation of PG&E-Owned, RPS-Eligible Generation

While PG&E is not proposing as part of its 2018 RPS Plan to develop additional utility-owned renewable facilities, its existing RPS portfolio contains a number of such facilities. To the extent that PG&E builds, operates, maintains, and decommissions its own RPS-eligible generation facilities, PG&E follows its internal standard protocols and practices to ensure public, workplace, and contractor safety. For example, PG&E's Employee Code of Conduct sets the standard that PG&E employees will put safety first.[76] PG&E's commitment to a safety-first culture is reinforced by a speak-up culture.[77] These tools were developed in collaboration with PG&E employees, leaders, and union leadership and are intended to provide clarity and support as employees strive to take personal ownership of safety at PG&E. Additionally, PG&E seeks all applicable regulatory approvals from governmental authorities with jurisdiction to enforce laws related to worker health and safety, impacts to the environment, and public health and welfare.

As more fully detailed in PG&E's testimony in its last General Rate Case ("GRC"),[78] the top priority of PG&E's Electric Supply organization is public and employee safety, and its goal is to safely operate and maintain its generation facilities. In general, PG&E ensures safety in the development and operation of its RPS-eligible facilities in the same manner as it does for its other UOG facilities. This includes the use of recognized best practices in the industry.

PG&E operates each of its generation facilities in compliance with all local, state and federal permit and operating requirements such as state and federal Occupational Safety and Health Administration ("OSHA") and the CPUC's General Order 167. PG&E does this by using internal controls to help manage the operations and maintenance of its generation facilities, including: (1) guidance documents; (2) operations reviews; (3) an incident reporting process; (4) a corrective action program; (5) an outage planning and scheduling process; (6) a project management process; and (7) a design change process.

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76 *See* PG&E, "Employee Code of Conduct" (February 2018) (available at http://www.pgecorp.com/aboutus/corp_gov/coce/employee_conduct_standards.shtml). *See*, *e.g.*, PG&E, "Contractor, Consultant, and Supplier Code of Conduct," p. 4 (available at https://www.pge.com/includes/docs/pdfs/b2b/purchasing/suppliers/SupplierCodeofConductPGE.pdf).

77 *See* PG&E, "Employee Code of Conduct" *supra*, p. 21 *et seq.*

78 *See* PG&E, *Prepared Testimony, 2017 GRC, Application 15-09-001*, Exhibit (PG&E-5), Energy Supply, pp. 1-18 to 1-19 (available at https://www.pge.com/en_US/about-pge/company-information/regulation/regulation.page).

PG&E's Environmental Services organization also provides direct support to the generation facilities, with a focus on regulatory compliance. Environmental consultants are assigned to each of the generating facilities and support the facility staff.

Regarding employee safety, Power Generation employees develop a safety action plan each year. This action plan focuses on various items such as clearance processes and electrical safety, switching and grounding observations, training and qualifications, expanding the use of Job Safety Analysis tools, peer-to-peer recognition, near-hit reporting, industrial ergonomics, and human performance. Employees also participate in activities developed and conducted by an employee-led Driver Awareness Team established for the sole purpose of improving driving.

The day-to-day safety work in the operation of PG&E's generation facilities consists of base activities such as:

- Industrial and office ergonomics training/evaluations
- Illness and injury prevention
- Health and wellness training
- Regulatory mandated training
- Contractor Safety Oversight Program,
- Training and recertification for the safety staff
- Culture based safety process
- Asbestos and lead awareness training
- Safety at Heights Program
- Safe driving training
- First responder training
- Preparation of safety tailboards and department safety procedures
- Proper use of personal protective equipment
- Incident investigations and communicating lessons learned
- Near Hit (close call) reporting
- Employee injury case management
- Safety performance recognition
- Public safety awareness
- Corrective Actions Program

The safety focus of PG&E's hydropower operations includes the safety of the public at, around, and/or downstream of PG&E's facilities; the safety of our personnel at and/or traveling to PG&E's hydro facilities; and the protection of personal property potentially affected by PG&E's actions or operations. Regarding public safety, PG&E has developed and implemented a comprehensive public safety program that includes: (1) public education, outreach and partnership with key agencies; (2) improved warning and hazard signage at hydro facilities; (3) enhanced emergency response preparedness, training, drills and coordination with emergency response organizations; and (4) safer access to hydro facilities and lands, including trail access, physical barriers, and canal escape routes.

PG&E has also funded specific hydro-related projects that correct potential public and employee safety hazards, such as Arc Flash Hazards, inadequate ground grids, and waterway, penstock, and other facility safety condition improvements.

Over the past several years, PG&E's Power Generation organization has been creating a culture of safety first with strong leadership expectations and an increasingly engaged workforce. Fundamental to a strong safety culture is a leadership team that believes every job can be performed safely and seeks to eliminate barriers to safe operations. Equally important is the establishment of an empowered grass roots safety team that acts to encourage safe work practices among peers. Power Generation's grass roots team is led by bargaining unit employees from across the organization who work to include safety best practices in all the work they do. These employees are closest to the day-to-day work of providing safe, reliable, and affordable energy for PG&E's customers and are best positioned to implement changes that can improve safety performance.

15.2. Development and Operation of Third-Party–Owned, RPS-Eligible Generation

The vast majority of PG&E's procurement of products to meet RPS requirements has been from third-party generation developers. In these cases, local, state and federal agencies that have review and approval authority over the generation facilities are charged with enforcing safety, environmental and other regulations for the Project, including decommissioning. PG&E's contract provisions reinforce the developer's obligations to safety by requiring them to operate in accordance with all applicable safety laws, rules and regulations as well as Prudent Electrical Practices, which are the continuously evolving industry standards for operations of similar electric generation facilities.

PG&E's recent contract provisions seek to instill a continuous improvement safety culture that mirrors PG&E's "Contractor Safety Standard" pursuant to D.15-07-014. These provisions require developers to demonstrate their use of safeguards, equipment and personnel training, and require reporting of Serious Incidents and Exigent Circumstances shortly after they occur. Such provisions were included in the executed agreements arising out of the 2014 and 2016 Energy Storage Requests for Offers ("RFOs") and could be incorporated in future RPS form PPAs if PG&E's RPS position resulted in a need for RPS procurement.

During the development process, PG&E receives monthly progress reports from generators who are developing new RPS-eligible resources where the output will be sold to PG&E. As part of this progress report, generators are required to provide the status of construction activities, including safety updates such as OSHA recordables and work stoppage information.

Safety is also addressed as part of a generator's interconnection process, which requires testing for safety and reliability of the interconnected generation. PG&E's general practice is to declare that a facility under contract has commenced deliveries under the PPA only after the interconnecting utility and the CAISO have concluded such testing and given permission to commence commercial operations.

The decommissioning of a third-party generation project is not addressed in the form contract. In many cases, it may be expected that a third-party generator may continue to operate its generation facility after the PPA has expired or terminated, perhaps with another off-taker. Any requirements and conditions for decommissioning of a generation facility owned by a third-party should be governed by the applicable permitting authorities.

16. **Energy Storage**

AB 2514, signed into law in September 2010, added Section 2837, which requires that the IOUs' RPS procurement plans incorporate any energy storage targets and policies that are adopted by the Commission as a result of its implementation of AB 2514. On October 17, 2013, the CPUC issued D.13-10-040 adopting an energy storage procurement framework and program design, requiring that PG&E execute 580 MW of storage capacity by 2020, with projects required to be installed and operational by no later than the end of 2024. In accordance with the guidelines in the decision, PG&E completed its 2014 and 2016 Energy Storage RFOs. On December 1, 2017, PG&E submitted six executed agreements that resulted from the 2016 Energy Storage RFO for CPUC approval.[79]

In January 2018, the CPUC authorized PG&E to launch an accelerated solicitation for energy storage projects to contribute to reliability needs for three specified local subareas in the northern central valley and in an area spanning Silicon Valley to the central coast (Pease, Bogue, and South Bay – Moss Landing local sub-areas). PG&E issued its RFO in February 2018 and received offers from numerous participants. After careful evaluation, PG&E selected and submitted for approval four projects to be located within the South Bay – Moss Landing local sub-area: one offer for a 182.5 MW utility-owned project and three offers for 385 MW of third-party owned projects, which include a 10 MW aggregation of customer-sited storage.[80] Energy storage procured to meet the local sub area need will be used to meet PG&E's AB 2514

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79 A.17-12-003. Application of Pacific Gas and Electric Company (U 39-E) for Approval of Agreements Resulting from Its 2016-2017 Energy Storage Solicitation and Related Cost Recovery.

80 Advice 5322-E, Energy Storage Contracts Resulting from PG&E's Local sub-area Request for Offers Per Res. E-4909, submitted June 29, 2018.

targets. These projects are also expected to help increase the overall flexibility of the grid to integrate high levels of wind and solar generation.

AB 2868, signed into law in September 2016, added Sections 2838.2 and 2838.3, which requires that the IOUs file applications for programs and investments to accelerate widespread deployment of distributed energy storage systems. In March 2018, PG&E filed its proposal with the CPUC to deploy 166.66 MW of distributed energy storage in compliance with AB 2868.[81]

PG&E would consider meeting its Energy Storage Program targets through eligible energy storage systems procured through its RPS process (to the extent that PG&E seeks authorization to solicit incremental RPS procurement in the future) and its Energy Storage RFOs, as well as other CPUC programs and channels such as the Self-Generation Incentive Program. PG&E's LCBF methodology considers the additional value offered by RPS-eligible generation facilities that incorporate energy storage. Further detail on PG&E's energy storage procurement can be found in its biennial Energy Storage Plan.[82]

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81 A.18-03-001, Application of PG&E for Approval of its 2018 Energy Storage Procurement and Investment Plan, filed March 1, 2018.

82 *See ibid.*

APPENDIX F.1

2019 Bundled RPS Energy Sale – Solicitation Protocol

~~August 20, 2018~~

March 15, 2019

2019 Bundled RPS Energy Sale - Solicitation Protocol

Issuance Date: __________, 2019

Table of Contents

LIST OF ATTACHMENTS

I. Overview

A. Overview

Pacific Gas and Electric Company ("PG&E") is issuing the 2019 Bundled Renewable Portfolio Standard ("RPS") Energy Sale Solicitation ("Solicitation" or "2019 Bundled RPS Sale") to solicit bids ("Bids") from participants ("Participants" or "Bidders") for bundled RPS-eligible energy and associated Renewable Energy Credits ("REC") (collectively, "Product") pursuant to a confirmation ("Agreement"). This Solicitation protocol ("Solicitation Protocol") describes the process by which PG&E seeks, evaluates, and accepts Bids in this solicitation from winning Bidders ("Buyers").

The 2019 Bundled RPS Sale complies with PG&E's 2018 RPS Plan, which was approved by the California Public Utilities Commission ("CPUC" or "Commission") in Decision (D.) ~~XX-XX-XXX.~~19-02-007).

Subject to Bid pricing and other factors in this Solicitation Protocol, PG&E seeks to sell a volume of Product commensurate with ~~Bid prices~~revenue of Bids received.

PG&E will make all sales according to the terms and conditions set forth in the Agreement. This Solicitation Protocol sets forth the procedures a Bidder must follow in order to participate in the Solicitation. Capitalized terms used in this Solicitation Protocol, but not otherwise defined herein, have the meanings set forth in the Agreement.

B. Bundled RPS Energy Sale Solicitation Communication

PG&E has established the 2019 Bundled RPS Energy Sale Solicitation website at http://www.pge.com/rfo under "2019 Bundled RPS Energy Sale Solicitation." This site will be where Bidders register and where all Solicitation documents, information, announcements and questions and answers are posted and available to Bidders.

To promote accuracy and consistency of the information provided to all Bidders, PG&E encourages Bidders to submit any inquiries via e-mail to RECSolicitations@pge.com for matters related to the Solicitation. With respect to matters of general interest raised by any Bidder, PG&E may, without reference to the specific Bidder raising such matter or initiating the inquiry, post the questions and responses on its website. PG&E may, in its sole discretion, decline to respond to any email or other inquiry.

Any exchange of material information regarding this Solicitation between Bidder and PG&E must be submitted to both PG&E and the Independent Evaluator ("IE"). The IE is an independent, third party evaluator who is required by CPUC D.04-12-048 to ensure this Solicitation is conducted in a reasonable and neutral manner.

C. Schedule

The Solicitation schedule is subject to change to conform to any CPUC requirements but otherwise is at the discretion of PG&E. PG&E will post any schedule changes on PG&E's Solicitation website. Also, as further described below, Bidders may register at PG&E's Request for Offer (RFO) website to receive notice of these and other Solicitation changes by electronic mail. PG&E will have no liability or responsibility to any Bidder for any change in the schedule or for failing to provide notice of any change.

The schedule for this Solicitation is (all times are in Pacific Prevailing Time):

Table 1: 2019 Bundled RPS Energy Sale Solicitation Schedule of Events

Date/Time	Event
Ongoing	Bidders may register online at PG&E's RFO website to receive notices regarding the Solicitation.
TBD	PG&E issues the Solicitation.
TBD	Bids Due. Bid(s) must be submitted to the online platform at Power Advocate.
TBD	PG&E notifies qualified Bidders.
TBD	PG&E and qualified Bidders ~~complete~~execute Agreement, which shall be subject to "CPUC Approval," as provided in the Agreement.
No later than 60 days after execution	PG&E submits Agreements for CPUC Approval.

D. Events in the Solicitation Schedule

a. Registration. Bidders may register online to receive announcements and updates about this Solicitation through www.pge.com/rfo.

b. Issuance. PG&E will issue the Solicitation and post the Solicitation Protocol, form of Agreement, and all other solicitation materials on the Solicitation website.

c. Bids Due. Bids must be submitted via Power Advocate and must include all of the documents described in Section IV, Required Information. By submitting a Bid(s) and responding to this Solicitation, the Bidder agrees to be bound by all of the terms, conditions and other provisions of this Solicitation and any changes or supplements to it that may be issued by PG&E.

d. PG&E Selects Bids. Selected Bids ("Selected Bids") will be notified via email. PG&E will select Bids according to the evaluation criteria described in Section III, Evaluation Criteria. Bids beyond the Selected Bids may be placed on a waitlist to be selected in order of evaluation results and selection constraints, should any Selected Bids fail to complete the Solicitation process.

e. Completion of Agreement. PG&E will complete Agreement with Participants with Selected Bids.

f. Execution and Regulatory Approval. Once PG&E and the Participants with Selected Bids execute Agreements, if any, resulting from this Solicitation, PG&E will submit all such Agreements to the CPUC for approval via an advice letter filing. Additional regulatory approval information is provided in Section VII, Regulatory Approval.

E. Disclaimers for Rejecting Bids and/or Terminating this Solicitation

This Solicitation does not constitute an offer to sell and creates no obligation to execute any Agreement or to enter into a transaction under an Agreement as a consequence of the Solicitation. PG&E shall retain the right at any time, at its sole discretion, to reject any Bid on the grounds that it does not conform to the terms and conditions of this Solicitation and reserves the right to request information at any time during the Solicitation process.

PG&E retains the discretion, subject to, if applicable, the approval of the CPUC, to: (a) reject any Bid for any reason, including but not limited to the basis that a Bid is the result of market manipulation or is not cost-competitive or any other applicable reason; (b) modify this Solicitation and the form Agreement as it deems appropriate to implement the Solicitation and to comply with applicable law or other decisions or direction provided by the CPUC; and (c) terminate the Solicitation should the CPUC not authorize PG&E to sell the Product in the manner proposed in this Solicitation. In addition, PG&E reserves the right to either suspend or terminate this Solicitation at any time if such suspension is required by or with the approval of the CPUC. PG&E will not be liable in any way, by reason of such withdrawal, rejection, suspension, termination or any other action described in this Solicitation Protocol to any Bidder, whether submitting a Bid or not.

II. Solicitation Product and Goals

PG&E is seeking to sell Product with the exact volume to be determined based on the ~~price~~total revenue of bids received.

A. Product Attributes

1. Bundled RPS-eligible energy and associated RECs from resources in PG&E's portfolio.
2. Price: NP15, ZP26 and/or SP15 Index + REC Price to be specified by Buyer.
3. Location: Buyer to choose energy deliveries at NP15 Trading Hub, ZP26 Trading Hub, or SP15 Trading Hub.
4. Scheduled Energy Deliveries: Energy deliveries may be in any months or hours that are mutually agreeable.
5. Delivery Term: ~~2019, 2020, 2021, 2022 and 2023.~~TBD

III. Evaluation Criteria

PG&E will evaluate Bids using the evaluation criteria outlined below. PG&E will evaluate Bids for each delivery year independently, which may result in the selection of Bids for non-consecutive delivery years from one Bidder.

A. Quantitative Evaluation

~~For~~PG&E plans to evaluate Bids ~~in~~based on a portfolio approach with the ~~Solicitation, PG&E will consider Price bid as~~objective of maximizing revenue from the ~~sole quantitative criterion~~bids received.

B. Qualitative Evaluation

For the Solicitation, PG&E may apply a qualitative adjustment factor for counterparties that have acceptable credit with PG&E and minimize proposed edits to the form of Agreement.

1. Credit

PG&E may consider the Participant's capability to perform all of its financial and financing obligations under the Agreement and PG&E's overall credit concentration with the Participant or its banks, including any of Participant's affiliates.

2. Agreement Modifications

PG&E may assess the materiality and cost impact of any of Participant's proposed modifications to the Agreement. PG&E has a preference for standardized Agreements. To the extent possible, PG&E requests Bidders limit edits to the Agreement to the following sections:

- Product (in limited circumstances)
- Quantity
- Green Attributes Price
- Energy Delivery Period
- Delivery Point
- Credit Terms

3. Other Qualitative Considerations

In addition to the criteria specifically listed above, PG&E may consider other qualitative factors that could impact the value of Bids, including, but not limited to: previous adverse commercial experience between PG&E and Participant; Participant concentration; and existence of an acceptable EEI Master Agreement between PG&E and Participant.

IV. Required Information

A. Submission Overview

All Bid submittal information pertaining to this Solicitation will be hosted on the Power Advocate site. Telephonic, hardcopy or facsimile transmission of a Bid is not acceptable. In order to participate in this Solicitation, Bidders must register and be accepted through Power Advocate at the Public Registration Link:

[TBD]

PG&E strongly encourages Bidders to register with Power Advocate well before Bids are due. Detailed instructions for submitting Bid(s) and using Power Advocate are on PG&E's Solicitation website.

Electronic Documents: The electronic documents for the attachments must be in a Microsoft Word, Excel file or Adobe Acrobat PDF file as applicable. For each document, please include the Bidder's company name in each file name.

B. Required Forms

1. Bid Package

The following documents, which are on the PG&E's Solicitation website, must be completed and included with each Bid~~:~~(s):

a. Bid Form (Attachment A)

   i. Bidder must provide all applicable information requested in the form, and all inputs must match the respective information provided in other required documentation.
   ii. PG&E will only accept one Bid per counterparty per delivery term. Brokers submitting on behalf of multiple counterparties may do so, but must designate the name of counterparty in the Bid Form.
   iii. PG&E will not accept Bids that are contingent on the selection of another bid;

b. Redline of Agreement (Attachment B);

c. Signed Non-Disclosure Agreement (Attachment C);

d. Documentation of Entity Legal Status from the California Secretary of State; and

e. Bidder or end-user counterparty must demonstrate that it has an "Active" legal status authorized by the California Secretary of State in order to engage in business with PG&E. A webpage screenshot verifying Bidder or end-user counterparty's "Active" legal status via the California Secretary of State's webpage is acceptable. The California Secretary of State website is ~~located at~~ located at https://businesssearch.sos.ca.gov/.

V. Confidentiality

No Bidder shall collaborate on or discuss with any other Bidder or potential Bidding strategies, the substance of any Bid(s), including without limitation the price or any other terms or conditions of any Bid(s), or whether PG&E has Selected Bids or not.

All information and documents in Bidder's Package that have been clearly identified and marked by Bidder as "Proprietary and Confidential" on each page on which confidential information appears shall be considered confidential information. PG&E shall not disclose such confidential information and documents to any third parties except for PG&E's employees, agents, counsel, accountants, advisors, or contractors who have a need to know such information and have agreed to keep such information confidential and except as provided otherwise in this section. In addition, Bidder's Package will be disclosed to the IE.

Notwithstanding the foregoing, it is expressly contemplated that the information and documents submitted by Bidder in connection with this Solicitation, including Bidder's confidential information, may be provided to the CPUC, its staff, and the Procurement Review Group ("PRG"), and established pursuant to D.02-08-071. PG&E retains the right to disclose any information or documents provided by Bidder to the CPUC, the PRG, in the advice letter filing or in order to comply with any applicable law, regulation, or any exchange, control area or California Independent System Operator rule, or order issued by a court or entity with competent jurisdiction over PG&E at any time even in the absence of a protective order, confidentiality agreement, or nondisclosure agreement, as the case may be, without notification to Bidder and without liability or any responsibility of PG&E to Bidder. PG&E cannot ensure that the CPUC will afford confidential treatment to Bidder's confidential information, or that confidentiality agreement or orders will be obtained from and/or honored by the PRG, the California Energy Commission, or the CPUC. By submitting a Bid, Bidder agrees to adhere and be bound by the confidentiality provisions described in this section.

The treatment of confidential information described above shall continue to apply to information related to Selected Bids.

VI. Procurement Review Group Review

Following completion of the evaluation and ranking of Bids, PG&E will submit the results of the evaluation and its recommendations to its PRG members. PG&E will consider any alternative recommendations proposed by the PRG. PG&E, in its sole discretion, shall determine whether any alternatives proposed by the PRG should be adopted. PG&E has no obligation to obtain the concurrence of the PRG with respect to any Bids.

PG&E assumes no responsibility for the actions of the PRG, including actions that may delay or otherwise affect the schedule for this Solicitation, including the timing of the selection of Bids and the obtaining of Regulatory Approval.

VII. Regulatory Approval

After Agreement execution, PG&E is required to submit executed Agreements to the CPUC for approval via an advice letter filing.

The effectiveness of any executed Agreement is expressly conditioned on PG&E's receipt of final and non-appealable CPUC approval of such Agreement ("Regulatory Approval").

VIII. Dispute Resolution

Except as expressly set forth in this Solicitation Protocol, by submitting a Bid, Bidder knowingly and voluntarily waives all remedies or damages at law or equity concerning or related in any way to the Solicitation, the Solicitation Protocol and/or any attachments to the Solicitation Protocol ("Waived Claims"). The assertion of any Waived Claims by Bidder may, to the extent that Bidder's Package has not already been disqualified, automatically disqualify such Bid from further consideration in the Solicitation.

By submitting a Bid, Bidder agrees that the only forums in which Bidder may assert any challenge with respect to the conduct or results of the Solicitation is through the Alternative Dispute Resolution ("ADR") services provided by the CPUC pursuant to Resolution ALJ-185, August 25, 2005. The ADR process is voluntary in nature, and does not include processes, such as binding arbitration, that impose a solution on the disputing parties. PG&E will consider the use of ADR under the appropriate circumstances. Additional information about this program is available on the CPUC's website at the following link: www.cpuc.ca.gov/PUBLISHED/Agenda_resolution/47777.htm.

Participant further agrees that other than through the ADR process, the only means of challenging the conduct or results of the Solicitation is a protest to an Advice Letter Filing seeking approval of one or more Agreements entered into as a result of the Solicitation, that the sole basis for any such protest shall be that PG&E allegedly failed in a material respect to conduct the Solicitation in accordance with this Solicitation Protocol, and the exclusive remedy available to Bidder in the case of such a protest shall be an order of the CPUC that PG&E again conduct any portion of the Solicitation that the CPUC determines was not previously conducted in accordance with the Solicitation Protocol. Bidder expressly waives any and all other remedies, including, without limitation, compensatory and/or exemplary damages, restitution, injunctive relief, interest, costs, and/or attorney's fees. Unless PG&E elects to do otherwise in its sole discretion during the pendency of such a protest or ADR process, the Solicitation and any related regulatory proceedings related to the Solicitation, will continue as if the protest had not been filed, unless the CPUC has issued an order suspending the Solicitation or PG&E has elected to terminate the Solicitation.

Bidder agrees to indemnify and hold PG&E harmless from any and all claims by any other Bidder asserted in response to the assertion of a Waived Claim by Bidder or as a result of a Bidder's protest to an advice letter filing with the CPUC resulting from the Solicitation.

Except as expressly provided in this Solicitation Protocol, nothing herein including Bidder's waiver of the Waived Claims as set forth above, shall in any way limit or otherwise affect the rights and remedies of PG&E. Nothing in this Solicitation Protocol is intended to prevent any Bidder from informally communicating with the CPUC or its staff regarding this solicitation.

IX. Termination of the Solicitation-Related Matters

PG&E reserves the right at any time, in its sole discretion, to terminate the Solicitation for any reason without prior notification to Bidders and without liability to, or responsibility of, PG&E or anyone acting on PG&E's behalf. Without limitation, grounds for termination of the Solicitation may include the assertion of any Waived Claims by a Bidder or a determination by PG&E that, following evaluation of the Bids, there are no Bids that meet the requirements of this Solicitation.

PG&E reserves the right to terminate further participation in this process by any Bidder, to accept any Bid or to enter into any Agreement, and to reject any or all Bids, all without notice and without assigning any reasons and without liability to PG&E or anyone acting on PG&E's behalf. PG&E shall have no obligation to consider any Bids.

In the event of termination of the Solicitation for any reason, PG&E will not reimburse Bidder for any expenses incurred in connection with the Solicitation. PG&E shall have no obligation to reimburse any Bidder's expenses regardless of whether such Bidder's Package is selected, not selected, rejected or disqualified. Unless earlier terminated, the Solicitation will terminate automatically upon the execution of one or more Agreements by Participants with Selected Bids. In the event that no Agreements are executed, then the solicitation will terminate automatically on ~~________, 2019.~~ ***[PG&E to insert date]***.

X. Bidder's Representations and Warranties

1. By submitting a Bid and clicking "Yes" to the "Acknowledgment of Protocol" section of the Bid Form, Bidder agrees to be bound by the conditions of the Solicitation, and makes the following representations, warranties, and covenants to PG&E, which representations, warranties, and covenants shall be deemed to be incorporated in their entireties into each of Bidder's Package. Bidder agrees that an electronic signature of a duly authorized representative of Bidder shall be the same as delivery of an executed original document for purposes of the Bid Form.

    - Bidder has read, understands and agrees to be bound by all terms, conditions and other provisions of this Solicitation Protocol;
    - Bidder has had the opportunity to seek independent legal and financial advice of its own choosing with respect to the Solicitation and this Solicitation Protocol, including the submittal forms and documents listed in this Solicitation Protocol which are posted on the RFO website;
    - Bidder has obtained all necessary authorizations, approvals and waivers, if any, required by Bidder to submit its Bid pursuant to the terms of this Solicitation Protocol and to enter into an Agreement with PG&E;
    - Bidder's Package complies with all applicable laws;

- Bidder has not engaged, and covenants that it will not engage, in any communications with any other actual or potential Bidder in the Solicitation concerning this Solicitation, price terms in Bidder's Package, or related matters and has not engaged in collusion or other unlawful or unfair business practices in connection with the Solicitation;

- Any Bid submitted by Bidder is subject only to PG&E's acceptance, in PG&E's sole discretion; and

- The information submitted by Bidder to PG&E in connection with the Solicitation and all information submitted as part of any Bid is true and accurate as of the date of Bidder's submission. Bidder also covenants that it will promptly update such information with PG&E upon any material change thereto.

2. By submitting a Bid, Bidder acknowledges and agrees:

   - That PG&E may rely on any or all of Bidder's representations, warranties, and covenants in the Solicitation (including any Bid submitted by Bidder); and

   - That in PG&E's evaluation of Bids pursuant to the Solicitation, PG&E has the right to disqualify a Bidder that is unwilling or unable to meet any other requirement of the Solicitation, as determined by PG&E in its sole discretion.

3. BY SUBMITTING A BID, BIDDER HEREBY ACKNOWLEDGES AND AGREES THAT ANY BREACH BY BIDDER OF ANY OF THE REPRESENTATIONS, WARRANTIES AND COVENANTS IN THESE SOLICITATION INSTRUCTIONS SHALL CONSTITUTE GROUNDS FOR IMMEDIATE DISQUALIFICATION OF SUCH BIDDER, IN ADDITION TO ANY OTHER REMEDIES THAT MAY BE AVAILABLE TO PG&E UNDER APPLICABLE LAW, AND DEPENDING ON THE NATURE OF THE BREACH, MAY ALSO BE GROUNDS FOR TERMINATING THE SOLICITATION IN ITS ENTIRETY.

APPENDIX F.2

2019 Bundled RPS Energy Sale Solicitation
Bid Form

~~August 20, 2018~~
March 15, 2019

Pacific Gas and Electric Company

2019 Bundled RPS Energy Sale Solicitation Bid Form

Contact Information	
Bidder Name:	
Bidder Type:	
Email:	
Phone:	
Street:	
City:	
State:	
Zip:	
Buyer/Counterparty:	
Buyer/Counterparty Type:	
Email:	
Phone:	
Street:	
City:	
State:	
Zip:	

Product & Bid Information	
Product:	
Delivery Location:	
Payment Index:	
Schedule or delivery requirements:	
Premium (+)/Discount (-) to Payment Index ($/MWh)	

Delivery Year	Bid Quantity
~~2019~~ TBD	
~~2020~~ TBD	
~~2021~~ TBD	
~~2022~~ TBD	
~~2023~~ TBD	

Acknowledgement of Protocol	
By selecting "Yes" Participant hereby agrees to the terms of the Solicitation Protocol. Participant acknowledges that any costs incurred to become eligible or remain eligible for the solicitation, and any costs incurred to prepare a bid for this solicitation are solely the responsibility of Participant.	
Title:	
Electronic Signature:	
Select "Yes" to certify that the typed name acts as your electronic signature.	

Participant Authorization	
By selecting "Yes" Participant hereby confirms that they are "a duly authorized representative of Participant."	
Title:	
Electronic Signature:	
Select "Yes" to certify that the typed name acts as your electronic signature.	

Attestation	
By providing the electronic signature below Participant hereby attests that all information provided in this Bid Package and in response to this REC Solicitation is true and correct to the best of Participant's knowledge as of the date such information is provided.	
Title:	
Electronic Signature:	
Select "Yes" to certify that the typed name acts as your electronic signature.	

APPENDIX F.3

EEI Master Power Purchase and Sale Agreement Short Term Sales Confirmation Between Pacific Gas and Electric Company

~~August 20, 2018~~
March 15, 2019

EEI MASTER POWER PURCHASE AND SALE AGREEMENT
SHORT TERM SALES CONFIRMATION
BETWEEN
PACIFIC GAS AND ELECTRIC COMPANY
AND
[**Buyer to insert its full name here in all caps**]

This confirmation ("Confirmation") confirms the transaction ("Transaction") between Pacific Gas and Electric Company, a California corporation, but limited for all purposes hereunder to its electric procurement and electric fuels functions ("Seller" or "Party B"), and [______________________________] [***Buyer to insert its full name, place of formation and type of entity***] ("Buyer" or "Party A"), each individually a "Party" and together the "Parties", effective as of the Execution Date, for the sale and purchase of the Product defined herein.

Except as otherwise expressly stated herein, this Confirmation is subject to, and incorporates by reference with the same force and effect as if set forth herein, all of the terms and provisions of the Parties' EEI Master Power Purchase and Sale Agreement, together with the Cover Sheet [and the amendments and annexes thereto] [***PG&E to identify any amendments or annexes here]***, dated as of [***MM/DD/YYYY***] [***PG&E to insert date in MM/DD/YYYY format***] (collectively, ["Master Agreement"] ["EEI Agreement" ***if no Collateral Annex***]) [, and the corresponding Collateral Annex and Paragraph 10 to the Collateral Annex thereto]. [Such Collateral Annex and Paragraph 10 to the Collateral Annex shall be referred to collectively herein as the "Collateral Annex"]. [The Master Agreement and the Collateral Annex shall be referred to collectively herein as the "EEI Agreement".] The EEI Agreement and this Confirmation shall be referred to collectively herein as the "Agreement."

Capitalized terms used but not defined in this Confirmation shall have the meanings ascribed to them in the EEI Agreement, the RPS (defined herein), or the Tariff (defined herein). If there is a conflict between the terms in this Confirmation and those in the EEI Agreement, this Confirmation shall control.

[PG&E to delete references to the Collateral Annex above if there is no existing Collateral Annex between the Parties]

[Standard contract terms and conditions shown in shaded text are those that "may not be modified" per CPUC Decisions ("D.") 07-11-025; D.10-03-021, as modified by D.11-01-025; and D.13-11-024.]

Seller: Pacific Gas and Electric Company		**Buyer:** [***Buyer to insert its name here***]
Contact Information:	**Name:** Pacific Gas and Electric Company ("Seller" or "Party B")	**Name:** [***Buyer to insert its contact name here***] ("Buyer" or "Party A")
	All Notices: P.O. Box 770000, Mail Code N12E San Francisco, CA 94177 Attn: Senior Manager, Contract Management Phone: (415) 973-8660 E-mail: [***PG&E to insert here***]	**All Notices:** [***Buyer to insert its address for Notices here***] Attn: [***Buyer to insert here***] Phone: [***Buyer to insert here***] Email: [***Buyer to insert here***]

	Invoices: Attn: Manager, Contract Settlements Phone: (415) 973-4277 Email:	**Invoices:** Attn: [***Buyer to insert here***] Phone: [***Buyer to insert here***] Email: [***Buyer to insert here***]
	Scheduling: Attn: Day-Ahead Scheduling Phone: (415) 973-6222 Email:	**Scheduling:** Attn: [***Buyer to insert here***] Phone: [***Buyer to insert here***] Email: [***Buyer to insert here***]
	Payments: Attn: Manager, Contract Settlements Phone: (415) 973-4277 Email:	**Payments:** Attn: [***Buyer to insert here***] Phone: [***Buyer to insert here***] Email: [***Buyer to insert here***]
	Wire Transfer: BNK: ABA: ACCT: Duns: Federal Tax ID Number:	**Wire Transfer:** BNK: ABA: ACCT: Duns: Federal Tax ID Number:
	Credit and Collections: **Credit and Collections:** Attn: Manager, Credit Risk Management Phone: (415) 972-5188 Email: PGERiskCredit@pge.com **Defaults:** With additional Notices of an Event of Default or Potential Event of Default to: Pacific Gas and Electric Company 77 Beale Street, Mail Code B30A San Francisco, CA 94105 Attn: Legal Department Email: [***PG&E to insert here***]	**Credit and Collections:** **Credit and Collections:** Attn: [***Buyer to insert here***] Phone: [***Buyer to insert here***] Email: [***Buyer to insert here***] **Collateral:** Attn: [***Buyer to insert here***] Phone: [***Buyer to insert here***] E-mail: [***Buyer to insert here***] **Defaults:** With additional Notices of an Event of Default or Potential Event of Default to: Address: [***Buyer to insert here***] Attn: [***Buyer to insert here***] Email: [***Buyer to insert here***]

ARTICLE 1
COMMERCIAL TERMS

<table>
<tr><td colspan="2">Seller: PACIFIC GAS AND ELECTRIC COMPANY</td><td>Buyer: [Buyer to insert its full name here in all caps]</td></tr>
<tr><td>Product:</td><td colspan="2">The Product shall consist of Electric Energy and associated Green Attributes from the Project, as further described and subject to the provisions herein.</td></tr>
<tr><td>Project:</td><td colspan="2">All Product sold hereunder shall be generated by the facility or facilities (“Project”) listed in Appendix A to this Confirmation or identified pursuant to Section 8.2 herein.

Seller shall have sole discretion throughout the Term to designate and re-designate, as applicable, the Project by selecting one or more of the facilities from Appendix A or pursuant to Section 8.2 herein.

Buyer shall not be entitled to, and shall not receive, any amount of Green Attributes produced by the Project that is in excess of the Total Quantity.

Buyer shall not be entitled to, and shall not receive, any amount of Electric Energy produced by the Project that is in excess of the Energy Quantity.</td></tr>
<tr><td>Quantity:</td><td colspan="2">(a) <u>For Green Attributes</u>: “Total Quantity”, with respect to an applicable year, shall be equal to those volumes of Green Attributes specified for that applicable year in the Delivery Term Quantity Schedule set forth below and shall be conveyed during the Green Attributes Delivery Period to Buyer as provided herein and subject to the limitation specified below with respect to each Calculation Period.

(b) <u>For Electric Energy</u>: “Energy Quantity”, with respect to an applicable year, shall be equal to those volumes of Electric Energy specified for that applicable year in the Delivery Term Quantity Schedule set forth below and shall be delivered during the Energy Delivery Period to Buyer as provided herein and subject to the limitation specified below with respect to each Calculation Period.

<table>
<tr><td colspan="3">Delivery Term Quantity Schedule</td></tr>
<tr><td>Year</td><td>Green Attributes (MWh)</td><td>Electric Energy (MWh)</td></tr>
<tr><td>[Buyer to insert]</td><td>[Buyer to insert]</td><td>[Buyer to insert]</td></tr>
</table></td></tr>
<tr><td>Energy Price:</td><td colspan="2">The Energy Price shall mean the Index Price for each MWh of Delivered Energy delivered to Buyer under this Agreement.</td></tr>
<tr><td>Green Attributes Price:</td><td colspan="2">The Green Attributes Price shall mean, with respect to an applicable year, that price in dollars for each MWh of Green Attributes conveyed to Buyer under this Agreement, as specified in the table below.

<table>
<tr><td>Year</td><td>Green Attributes Price ($)</td></tr>
<tr><td>[Buyer to insert]</td><td>[Buyer to insert]</td></tr>
</table></td></tr>
<tr><td>Term of Transaction:</td><td colspan="2">Except as otherwise provided herein, the term of the Transaction shall commence upon the Execution Date and shall continue until the end of the Delivery Term and the satisfaction of all other obligations of the Parties under this Agreement (“Term”).</td></tr>
</table>

	This Confirmation, and the Transaction and Term hereunder, shall terminate early in the event of a failure to satisfy the Green Attributes Condition Precedent defined below or as otherwise provided in the Agreement. Termination because of a failure to satisfy the Green Attributes Condition Precedent shall terminate all of the Parties' obligations under the Confirmation as of the Transaction Termination Date as provided in Section 4.2, except for the Parties' confidentiality obligations under Article 9 herein.
Credit Requirements:	(a) This Confirmation's credit requirements for the Electric Energy portion of the Product shall be governed by the EEI Agreement. (b) This Confirmation's credit requirements for the Green Attributes portion of the Product shall apply as specified below: (i) If the EEI Agreement has a Collateral Annex, then the Exposure Amount for the Green Attributes portion of the Product shall be equal to the product of the following: (I) fifteen percent (15%), multiplied by (II) the volume of the undelivered Green Attributes, multiplied by (III) the Green Attributes Price. (ii) In the event the EEI Agreement does *not* have a Collateral Annex *and* Section 8.2(c), entitled "Collateral Threshold" with respect to "Party B Credit Protection", of the EEI Agreement applies, then the Termination Payment for the Green Attributes portion of the Product to be delivered to Party B as described in Section 8.2(c) of the EEI Agreement shall be equal to the product of the following: (I) fifteen percent (15%), multiplied by (II) the volume of the undelivered Green Attributes, multiplied by (III) the Green Attributes Price. (c) Section 8.1 of the EEI Agreement, entitled "Party A Credit Protection", and all corresponding provisions of (i) the Cover Sheet to Section 8.1 of the EEI Agreement and (ii) the Collateral Annex with respect to such Section 8.1 and the applicable provisions thereto of Paragraph 10 to the Collateral Annex do not apply to this Confirmation.
Delivery Term:	The "Delivery Term" shall consist of both the Energy Delivery Period and the Green Attributes Delivery Period.
Energy Delivery Period:	Subject to the satisfaction, or waiver in writing by both Parties, of the Green Attributes Condition Precedent, the "Energy Delivery Period" shall (1) commence as of the later of [***MM/DD/YYYY***] [***Buyer to insert date in MM/DD/YYYY format***] and that date upon which CPUC Approval occurs, and (2) end on the earlier of the conclusion of hour ending 2400 (PPT) on [***MM/DD/YYYY***] [***Buyer to insert date in MM/DD/YYYY format for short-term transaction***] and that date upon which the amount of Electric Energy delivered by Seller satisfies the Energy Quantity.
Green Attributes Delivery Period:	Subject to the satisfaction, or waiver in writing by both Parties, of the Green Attributes Condition Precedent, the "Green Attributes Delivery Period" shall commence on the first day that Seller conveys Green Attributes to Buyer and shall end on that date upon which the amount of Green Attributes conveyed to Buyer satisfies the Total Quantity. Seller shall convey Green Attributes to Buyer in the form of WREGIS Certificates. Seller shall transfer WREGIS Certificates into Buyer's WREGIS account in an amount required to satisfy the Total Quantity.

Delivery Point:	The "Delivery Point" where Buyer shall take possession of the Electric Energy shall be [NP15 / SP15 / ZP26]. [***Buyer to designate***]
Scheduling Obligations:	Seller, or a qualified third party designated by Seller, shall act as Scheduling Coordinator for the Project. Buyer hereby authorizes Seller, or its third-party Scheduling Coordinator designee, to deliver the Electric Energy to the CAISO at the Delivery Point as an agent on Buyer's behalf.
Condition Precedent to the Green Attributes Obligations:	Notwithstanding any other provision of this Confirmation to the contrary, all of the Parties' obligations except for the Parties' confidentiality obligations under Article 9 herein, are conditioned upon [(a)] PG&E's receipt, or the Parties' written waiver, of CPUC Approval as defined below [; and (b) PG&E's receipt of the Performance Assurance from Buyer no later than five (5) Business Days following PG&E's Notice of CPUC Approval (defined below)] ([collectively,]"Green Attributes Condition Precedent").

ARTICLE 2
DEFINITIONS

2.1 "Balancing Authority" has the meaning set forth in the CAISO Tariff.

2.2 "Balancing Authority Area" has the meaning set forth in the CAISO Tariff.

2.3 "Broker or Index Quotes" means quotations solicited or obtained in good faith from (a) regularly published and widely-distributed daily forward price assessments from a broker that is not an Affiliate of either Party and who is actively participating in markets for the relevant Products or (b) end-of-day prices for the relevant Products published by exchanges which transact in the relevant markets.

2.4 "Business Day" means all calendar days other than those days on which the Federal Reserve member banks in New York City are authorized or required by law to be closed, and shall be between the hours of 8:00 a.m. and 5:00 p.m. Pacific Prevailing Time for the relevant Party's principal place of business where the relevant Party, in each instance unless otherwise specified, shall be the Party from whom the Notice, payment or delivery is being sent and by whom the Notice or payment or delivery is to be received.

2.5 "CAISO" means the California Independent System Operator Corporation or any successor entity performing similar functions.

2.6 "CAISO Grid" has the same meaning as "CAISO Controlled Grid" as defined in the CAISO Tariff.

2.7 "California Renewables Portfolio Standard" or "RPS" means the renewable energy program and policies established by California State Senate Bills 1078, X1 - 2 and 350, codified in California Public Utilities Code Sections 399.11 through 399.32 and California Public Resources Code Sections 25740 through 25751, as such provisions are amended or supplemented from time to time.

2.8 "CARB" means the California Air Resources Board or its successor agency.

2.9 "CEC" means the California Energy Commission or its successor agency.

2.10 “Contract Price” means the Energy Price plus the Green Attributes Price.

2.11 “CPUC” means the California Public Utilities Commission or its successor entity.

2.12 “CPUC Approval” means a final and non-appealable order of the CPUC, without conditions or modifications unacceptable to the Parties, or either of them, which contains the following terms:

(a) approves this Agreement in its entirety, including payments to be made by the Buyer, subject to CPUC review of the Buyer's administration of the Agreement; and

(b) finds that any procurement pursuant to this Agreement is procurement from an eligible renewable energy resource for purposes of determining Buyer's compliance with any obligation that it may have to procure eligible renewable energy resources pursuant to the California Renewables Portfolio Standard (Public Utilities Code Section 399.11 *et seq.*), Decision 03-06-071, or other applicable law.

CPUC Approval will be deemed to have occurred on the date that a CPUC decision containing such findings becomes final and non-appealable.

For the purpose of this Section 2.12, a CPUC Energy Division disposition which contains such findings, or deems approved an advice letter requesting such findings, shall be deemed to satisfy the CPUC decision requirement set forth above.

Also, for the purpose of this Section 2.12 only, the references therein to “Buyer” shall mean “Seller”.

2.13 “Credit Rating” means, with respect to any entity, (a) the rating then assigned to such entity’s unsecured, senior long-term debt obligations (not supported by third party credit enhancements), or (b) if such entity does not have a rating for its unsecured, senior long-term debt obligations, then the rating assigned to such entity as an issuer rating by S&P and/or Moody’s. If the entity is rated by both S&P and Moody’s and such ratings are not equivalent, the lower of the two ratings shall determine the Credit Rating. If the entity is rated by either S&P or Moody’s, but not both, then the available rating shall determine the Credit Rating.

2.14 “Delivered Energy” means the Electric Energy from the Project that is delivered by Seller to Buyer at the Delivery Point.

2.15 “Electric Energy” means three-phase, 60-cycle alternating current electric energy measured in MWh and net of auxiliary loads and station electrical uses (unless otherwise specified).

2.16 “Eligible Renewable Energy Resource” or “ERR” has the meaning set forth in California Public Utilities Code Section 399.12 and California Public Resources Code Section 25741, as either code provision is amended or supplemented from time to time.

2.17 “Execution Date” means the latest signature date found on the signature page of this Agreement.

2.18 “Force Majeure” means an event or circumstance which prevents one Party from performing its obligations under this Agreement, which event or circumstance was not anticipated as of the Execution Date, which is not within the reasonable control of, or the result of the negligence of, the

Claiming Party, and which, by the exercise of due diligence, the Claiming Party is unable to overcome or avoid or cause to be avoided. Force Majeure shall not be based on (a) the loss of Buyer's markets; (b) Buyer's inability economically to use or resell the Product purchased hereunder; (c) the loss or failure of Seller's supply unless caused by a force majeure event at the Project; or (d) Seller's ability to sell the Product at a price greater than the Contract Price. Neither Party may raise a claim of Force Majeure based in whole or in part on curtailment by a Transmission Provider unless (i) such Party has contracted for firm transmission with a Transmission Provider for the Product to be delivered to or received at the Delivery Point and (ii) such curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the Transmission Provider's tariff; provided, however, that existence of the two foregoing factors shall not be sufficient to conclusively or presumptively prove the existence of a Force Majeure absent a showing of other facts and circumstances which in the aggregate with such factors establish that a Force Majeure as defined in the first sentence hereof has occurred.

2.19 "Governmental Authority" means any federal, state, local or municipal government, governmental department, commission, board, bureau, agency, or instrumentality, or any judicial, regulatory or administrative body, having jurisdiction as to the matter in question.

2.20 "Green Attributes" means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Project, and its avoided emission of pollutants. Green Attributes include but are not limited to Renewable Energy Credits, as well as: (a) any avoided emission of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (b) any avoided emissions of carbon dioxide (CO2), methane (CH4), nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change, or otherwise by Law, to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere[1]; (c) the reporting rights to these avoided emissions, such as Green Tag Reporting Rights. Green Tag Reporting Rights are the right of a Green Tag Purchaser to report the ownership of accumulated Green Tags in compliance with federal or state Law, if applicable, and to a federal or state agency or any other party at the Green Tag Purchaser's discretion, and include without limitation those Green Tag Reporting Rights accruing under Section 1605(b) of The Energy Policy Act of 1992 and any present or future federal, state, or local Law, regulation or bill, and international or foreign emissions trading program. Green Tags are accumulated on a MWh basis and one Green Tag represents the Green Attributes associated with one (1) MWh of Electric Energy. Green Attributes do not include (i) any Electric Energy, capacity, reliability or other power attributes from the Project, (ii) production tax credits associated with the construction or operation of the Project and other financial incentives in the form of credits, reductions, or allowances associated with the Project that are applicable to a state or federal income taxation obligation, (iii) fuel-related subsidies or "tipping fees" that may be paid to Seller to accept certain fuels, or local subsidies received by the generator for the destruction of particular preexisting pollutants or the promotion of local environmental benefits, or (iv) emission reduction credits encumbered or used by the Project for compliance with local, state, or federal operating and/or air quality permits. If the Project is a biomass or biogas facility and Seller receives any tradable Green Attributes based on the greenhouse gas reduction benefits or other emission offsets attributed to its fuel usage, it shall provide Buyer with sufficient Green Attributes to ensure that there are zero net emissions associated with the production of electricity from the Project.

2.21 "Index Price" means the Trading Hub price (as defined in the CAISO Tariff) associated with the Delivered Energy to the Delivery Point for each applicable hour as published by the CAISO on

[1] Avoided emissions may or may not have any value for GHG compliance purposes. Although avoided emissions are included in the list of Green Attributes, this inclusion does not create any right to use those avoided emissions to comply with any GHG regulatory program.

the CAISO website or any successor thereto, unless a substitute publication and/or index is mutually agreed to by the Parties.

2.22 "Law" means any statute, law, treaty, rule, regulation, CEC guidance document, ordinance, code, permit, enactment, injunction, order, writ, decision, authorization, judgment, decree or other legal or regulatory determination or restriction by a court or Governmental Authority of competent jurisdiction, including any of the foregoing that are enacted, amended, or issued after the Execution Date, and which becomes effective after the Execution Date; or any binding interpretation of the foregoing. For the purposes of the definition of "CPUC Approval" in Section 2.12 and Sections 6.1(a), 6.1(b) and 8.3(b) in this Confirmation, the term "law" shall have the meaning set forth in this definition.

2.23 "Letter of Credit" means an irrevocable, non-transferable, standby letter of credit the form of which shall be substantially as contained in Appendix B to this Agreement; provided that, if the issuer is a U.S. branch of a foreign commercial bank, the intended beneficiary may require changes to such form; and the issuer must be a Qualified Institution on the date of delivery of the Letter of Credit to the Secured Party. In case of a conflict of this definition with any other definition of "Letter of Credit" contained in the EEI Agreement or any exhibit or annex thereto, this definition shall supersede any such other definition for purposes of the Transaction to which this Agreement applies.

2.24 "Market Quotation Average Price" means the arithmetic mean of the quotations solicited in good faith from not less than three (3) Reference Market-Makers (as hereinafter defined); provided, however, that the Party obtaining the quotes shall use reasonable efforts to obtain good faith quotations from at least five (5) Reference Market-Makers and, if at least five (5) such quotations are obtained, the Market Quotation Average Price shall be determined by disregarding the highest and lowest quotations and taking the arithmetic mean of the remaining quotations. The quotations shall be based on the offers to sell or bids to buy, as applicable, obtained for transactions substantially similar to each Terminated Transaction. The quote must be obtained assuming that the Party obtaining the quote will provide sufficient credit support for the proposed transaction. Each quotation shall be obtained, to the extent reasonably practicable, as of the same day and time (without regard to different time zones) on or as soon as reasonably practicable after the relevant Early Termination Date. The day and time as of which those quotations are to be obtained will be selected in good faith by the Party obtaining the quotations and in accordance with the Notice provided pursuant to Section 5.2 of the EEI Agreement, which designates the Early Termination Date. If fewer than three quotations are obtained, it will be deemed that the Market Quotations Average Price in respect of such Terminated Transaction or group of Terminated Transactions cannot be determined. For purposes of this Section 2.24, "Reference Market-Maker" means a leading dealer in the relevant market selected by a Party determining its exposure in good faith from among dealers of the highest credit standing which satisfy all the criteria that such Party applies generally at the time in deciding whether to offer or to make an extension of credit.

2.25 "Notice" means written communications by a Party to be delivered by hand delivery, United States mail, overnight courier service, or electronic messaging (e-mail). The contacts table of this Confirmation contains the names and addresses to be used for Notices.

2.26 "Qualified Institution" means either a U.S. commercial bank, or a U.S. branch of a foreign bank acceptable to the Beneficiary Party in its sole discretion; and in each case such bank must (i) have a Credit Rating of at least: (a) "A-, with a stable designation" from S&P and "A3, with a stable designation" from Moody's, if such bank is rated by both S&P and Moody's; or (b) "A-, with a stable designation" from S&P or "A3, with a stable designation" from Moody's, if such bank is rated by either S&P or Moody's, but not both, even if such bank was rated by both S&P and Moody's as of the date of issuance of the Letter of Credit but ceases to be rated by either, but not both of those ratings agencies, and (ii) have assets of at least $10 billion US Dollars.

2.27 "Real-Time Market" has the meaning set forth in the Tariff and shall include any market that CAISO may establish prior to or during the Term that clears at an interval between the Day-Ahead Market and the Real-Time Market.

2.28 "Renewable Energy Credit" or "REC" has the meaning set forth in California Public Utilities Code Section 399.12(h) and CPUC Decision 08-08-028, as may be amended from time to time or as further defined or supplemented by Law.

2.29 "Replacement Price" means the price at which Buyer, acting in a commercially reasonable manner, purchases for delivery at the Delivery Point a replacement for any Product specified in a Transaction but not delivered by Seller, plus (a) costs reasonably incurred by Buyer in purchasing such substitute Product and (b) additional transmission charges, if any, reasonably incurred by Buyer to the Delivery Point, or absent a purchase, the market price at the Delivery Point for such Product not delivered as determined by Buyer in a commercially reasonable manner; provided, however, in no event shall such price include any penalties, ratcheted demand or similar charges, nor shall Buyer be required to utilize or change its utilization of its owned or controlled assets or market positions to minimize Seller's liability. For the purposes of this definition, Buyer shall be considered to have purchased replacement Product to the extent Buyer shall have entered into one or more arrangements in a commercially reasonable manner whereby Buyer repurchases its obligation to sell and deliver the Product to another party at the Delivery Point.

2.30 "Sales Price" means the price at which Seller, acting in a commercially reasonable manner, resells any Product not received by Buyer, deducting from such proceeds any (a) costs reasonably incurred by Seller in reselling such Product and (b) additional transmission charges, if any, reasonably incurred by Seller in delivering such Product to the third party purchasers, or absent a sale, the market price at the Delivery Point for such Product not received as determined by Seller in a commercially reasonable manner; provided, further, that in no event shall such price include any penalties, ratcheted demand or similar charges, nor shall Seller be required to utilize or change its utilization of its owned or controlled assets, including contractual assets, or market positions to minimize Buyer's liability. For purposes of this definition, Seller shall be considered to have resold such Product to the extent Seller shall have entered into one or more arrangements in a commercially reasonable manner whereby Seller repurchases its obligation to purchase and receive the Product from another party at the Delivery Point.

2.31 "Tariff" means the CAISO Fifth Replacement FERC Electric Tariff and protocol provisions, including any CAISO-published procedures or business practice manuals, as they may be amended, supplemented or replaced (in whole or in part) from time to time.

2.32 "Transactions" as used in the EEI Agreement shall mean the "Transaction" as defined in the preamble above.

2.33 "WREGIS" means the Western Renewable Energy Generation Information System or any successor renewable energy tracking program.

2.34 "WREGIS Certificate" has the same meaning as "Certificate" as defined by WREGIS in the WREGIS Operating Rules and are designated as eligible for complying with the California Renewables Portfolio Standard.

2.35 "WREGIS Operating Rules" means the operating rules and requirements adopted by WREGIS.

ARTICLE 3
CONVEYANCE OF ELECTRIC ENERGY AND GREEN ATTRIBUTES

3.1 Seller's Delivery of Electric Energy.

Subject to the terms and conditions of this Agreement, beginning on the first day of the Energy Delivery Period and continuing until the last day of the Energy Delivery Period, Seller shall deliver and sell, and Buyer shall purchase and receive, the Delivered Energy.

3.2 Seller's Conveyance of Green Attributes.

(a) Green Attributes. Subject to the terms and conditions of this Agreement, beginning on the first day of the Green Attributes Delivery Period and continuing until the last day of the Green Attributes Delivery Period, Seller shall convey and sell, and Buyer shall purchase and receive, those Green Attributes associated with the Delivered Energy.

(i) Seller represents and warrants that Seller holds the rights to such Green Attributes from the Project and Seller agrees to convey such Green Attributes to Buyer as included in the delivery of the Product from the Project subject to the terms and conditions of this Agreement. ***[To the extent the Project is a biomethane facility, the Parties shall modify this section as necessary to ensure that it, and the definition of "Green Attributes", will not conflict with necessary language that will be added to address biomethane transactions, pursuant to CPUC D.13-11-024, pgs 21-24.]***

(ii) As set forth above, Seller shall convey only that amount of Green Attributes required to meet the Total Quantity and shall do so only during the Green Attributes Delivery Period.

(b) The Green Attributes in the amount of the Total Quantity shall be deemed to be conveyed to and received by Buyer under this Confirmation as set forth herein. During the Green Attributes Delivery Period, Seller shall convey to Buyer the Green Attributes associated with the Delivered Energy within the later of: (A) twenty-five (25) Business Days following the occurrence of both (I) the deposit into Seller's WREGIS account of the WREGIS Certificates for the Green Attributes for the applicable Calculation Period and (II) Buyer's payment of the Monthly Cash Settlement Amount in accordance with Article 5 herein; and (B) twenty-five (25) Business Days following the satisfaction, or written waiver by both Parties, of the Green Attributes Condition Precedent. Seller shall transfer such WREGIS Certificates in an amount equivalent to the Total Quantity to Buyer's WREGIS account such that all right, title and interest in and to the WREGIS Certificates shall transfer from Seller to Buyer.

ARTICLE 4
CPUC FILING AND APPROVAL

4.1 Filing for CPUC Approval.

Within sixty (60) days after the Execution Date, Seller shall file with the CPUC a request for CPUC Approval. Buyer shall use commercially reasonable efforts to support Seller in obtaining CPUC Approval. Seller shall have no obligation to seek rehearing or to appeal a CPUC decision which fails to approve this Confirmation or which contains findings required for CPUC Approval with conditions or modifications unacceptable to either Party. Notwithstanding anything to the contrary in the Confirmation, Seller shall not have any obligation or liability to Buyer or any third party for any action or inaction of the CPUC or other Governmental Authority affecting the approval or status of this Confirmation as a transaction eligible for portfolio content category 1, as defined in California Public Utilities Code Section 399.16(b)(1).

4.2 Termination Right and Transaction Termination Date.

In the event that: (a) the CPUC issues a final and non-appealable order not approving this Agreement in its entirety, (b) the CPUC issues a final and non-appealable order which contains conditions or modifications unacceptable to either Party, or (c) approval by the CPUC has not been received by Seller on or before sixty (60) days from the date on which Seller files for CPUC Approval, then either Party may, in its sole discretion, elect to terminate this Agreement upon Notice to the other Party provided in accordance with Article 10.7 of the EEI Agreement. Such Notice shall become effective one (1) Business Day after its provision. The effective date of the Notice shall constitute the "Transaction Termination Date". Any termination elected and noticed in accordance with this Section 4.2 shall terminate all of the Parties' rights and obligations under the Agreement as of the Transaction Termination Date, except for the Parties' confidentiality obligations under Article 9 herein.

4.3 Effect of Termination.

Any termination properly exercised by a Party under Section 4.2 shall be without liability or obligation, except for the Parties' confidentiality obligations under Article 9 herein, and shall have no effect on the status of the EEI Agreement.

ARTICLE 5
COMPENSATION

5.1 Calculation Period.

The "Calculation Period" shall be each calendar month or portion thereof that Delivered Energy was conveyed to Buyer and for which associated Green Attributes will be transferred to Buyer under this Confirmation as described in Section 3.2(b).

5.2 Monthly Cash Settlement Amount.

Buyer shall pay Seller the Monthly Cash Settlement Amount, in arrears, for each Calculation Period. The "Monthly Cash Settlement Amount" for a particular Calculation Period shall be equal to the sum of (a) plus (b) minus (c), where:

(a) equals the sum, over all hours of the Calculation Period, of the applicable Energy Price for each hour of Delivered Energy, multiplied by the quantity of Delivered Energy during that hour; and

(b) equals the Green Attributes Price multiplied by the quantity of Green Attributes (in MWhs) that will be conveyed as described in Section 3.2(b) and that are associated with the Delivered Energy in the Calculation Period; and

(c) equals the sum, over all hours of the Calculation Period, of the applicable Energy Price for each hour of Delivered Energy, multiplied by the quantity of Delivered Energy during that hour.

5.3 Payment Date.

Notwithstanding anything to the contrary in Article Six of the EEI Agreement, payment of each Monthly Cash Settlement Amount by Buyer to Seller under this Confirmation shall be due and payable four (4) calendar months following the applicable Calculation Period and on or before the later of: (a) the twentieth (20th) day of the month in which the Buyer receives from Seller an invoice for the Calculation Period to which the Monthly Cash Settlement Amount pertains, and (b) ten (10) days following the date of Buyer's receipt of an invoice issued by Seller for such applicable Calculation Period; provided that, if such payment due date is not a Business Day, then on the next Business Day. Payment to Seller shall be made by wire transfer pursuant to the Notices section of this Agreement.

5.4 Invoices.

The invoice shall include a statement detailing the amount of Delivered Energy, and associated Green Attributes, transferred to Buyer during the applicable Calculation Period. For purposes of this Confirmation, Buyer shall be deemed to have received an invoice upon Buyer's receipt by e-mail of such invoice in PDF format from Seller. Invoices to Buyer shall be sent by email to: **[*Buyer to insert*]**

ARTICLE 6
REPRESENTATIONS, WARRANTIES AND COVENANTS

6.1 Seller's Representations, Warranties, and Covenants.

(a) Seller Representations and Warranties. Seller, and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement that: (i) the Project qualifies and is certified by the CEC as an Eligible Renewable Energy Resource ("ERR") as such term is defined in Public Utilities Code Section 399.12 or Section 399.16; and (ii) the Project's output delivered to Buyer qualifies under the requirements of the California Renewables Portfolio Standard. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law.

(b) Seller and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement the Renewable Energy Credits transferred to Buyer conform to the definition and attributes required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law.

(c) Seller warrants that all necessary steps to allow the Renewable Energy Credits transferred to Buyer to be tracked in the Western Renewable Energy Generation Information System will be taken prior to the first delivery under the contract.

(i) For the avoidance of doubt, the term "contract" as used in the immediately preceding paragraph means this Confirmation.

(ii) For further clarity, the phrase "first delivery" as used in the immediately preceding paragraph means the first date of the Green Attributes Delivery Period.

(d) In addition to the foregoing, Seller warrants, represents and covenants, as of the Execution Date and throughout the Delivery Term, that:

(i) Seller has the contractual rights to sell all right, title, and interest in the Product required to be delivered hereunder;

(ii) Seller has not sold the Product required to be delivered hereunder to any other person or entity;

(iii) Seller is a "forward contract merchant" within the meaning of the United States Bankruptcy Code (as in effect as of the Execution Date of this Confirmation);

(iv) at the time of delivery, all rights, title, and interest in the Product required to be delivered hereunder are free and clear of all liens, taxes, claims, security interests, or other encumbrances of any kind whatsoever;

(v) Seller shall not substitute or purchase any Product from any generating resource other than the Project or the market for delivery hereunder; and

(vi) the facility(s) designated by Seller as the Project and all electrical output from the facility(s) designated as the Project are, or will be by the first date of the Green Attributes Delivery Period, registered with WREGIS as RPS-eligible.

(e) Seller makes no representation, warranty or covenant with respect to any portfolio content category designation pursuant to California Public Utilities Code Section 399.16 nor any eligibility of the Product to qualify as excess procurement pursuant to California Public Utilities Code Section 399.13(a)(4)(B).

(f) As of the Execution Date and throughout the Energy Delivery Period, Seller represents, warrants and covenants that the Project meets the criteria in either (A) or (B):

(A) The Project either has a first point of interconnection with a California balancing authority, or a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area; or

(B) The Project has an agreement to dynamically transfer electricity to a California balancing authority.

(g) If and to the extent that the Product sold by Seller is a resale of part or all of a contract between Seller and one or more third parties, Seller represents, warrants and covenants that the resale complies with the following conditions in (i) through (iv) below as of the Execution Date and throughout the Energy Delivery Period:

(i) The original upstream third-party contract(s) meets the criteria of California Public Utilities Code Section 399.16(b)(1)(A);

(ii) This Agreement transfers only Electric Energy and Green Attributes that have not yet been generated prior to the commencement of the Energy Delivery Period;

(iii) The Delivered Energy transferred hereunder is transferred to Buyer in real time; and

(iv) If the Project has an agreement to dynamically transfer electricity to a California balancing authority, the transactions implemented under this Agreement are not contrary to any condition imposed by a balancing authority participating in the dynamic transfer arrangement.

6.2 To the extent a change in Law occurs after the Execution Date that causes the representations, warranties, and/or covenants in Section 6.1or this Section 6.2 that continue beyond the Execution Date to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in Law.

6.3 "Commercially reasonable efforts" as set forth in this Article 6 and as applicable to Seller only shall not require Seller to incur out-of-pocket expenses in excess of twenty-five thousand dollars ($25,000.00) in the aggregate during the Term.

ARTICLE 7
TERMINATION AND CALCULATION OF TERMINATION PAYMENT

In the event this Transaction becomes a Terminated Transaction pursuant to Section 5.2 of the EEI Agreement, then the Settlement Amount with respect to this Transaction shall not be calculated in accordance with the EEI Agreement, but instead shall be calculated as follows:

The Non-Defaulting Party shall determine its Gains and Losses by determining the Market Quotation Average Price for the Terminated Transaction. In the event the Non-Defaulting Party is not able, after commercially reasonable efforts, to obtain the Market Quotation Average Price with respect to the Terminated Transaction, then the Non-Defaulting Party shall calculate its Gains and Losses for the Terminated Transaction in a commercially reasonable manner by calculating the arithmetic mean of the quotes of at least three (3) Broker or Index Quotes based on the offers to sell or bids to buy, as applicable, obtained for transactions substantially similar to the Terminated Transaction. Such Broker or Index Quotes must be obtained assuming that the Party obtaining the quote will provide sufficient credit support for the proposed transaction. In the event the Non-Defaulting Party is not able, after commercially reasonable efforts to obtain at least three (3) such Broker or Index Quotes with respect to the Terminated Transaction, then the Non-Defaulting Party shall calculate its Gains and Losses for such Terminated Transaction in a commercially reasonable manner by reference to information supplied to it by one or more third parties including, without limitation, quotations (either firm or indicative) of relevant rates, prices, yields, yield curves, volatilities, spreads or other relevant market data in the relevant markets. Third parties supplying such information may include, without limitation, dealers in the relevant markets, end-users of the relevant product, information vendors and other sources of market information; provided, however, that such third parties shall not be Affiliates of either Party. Only in the event the Non-Defaulting Party is not able, after using commercially reasonable efforts, to obtain such third-party information, then the Non-Defaulting Party shall calculate its Gains and Losses for such Terminated Transaction in a commercially reasonable manner using relevant market data it has available to it internally.

ARTICLE 8
GENERAL PROVISIONS

8.1 <u>Buyer Audit Rights</u>.

In addition to any audit rights provided under the EEI Agreement, Seller shall, during the Term as may be requested by Buyer, provide documentation (which may include, for example, meter data as recorded by a meter approved by the Project's governing Balancing Authority) sufficient to demonstrate that the Product has been conveyed and delivered to Buyer.

8.2 <u>Facility Identification</u>.

Seller shall have sole discretion throughout the Term to designate and re-designate, as applicable, the Project by selecting one or more of the facilities from Appendix A or by identifying one or more facilities as provided herein. If Seller determines that any Product to be delivered in a calendar month shall be from a facility or facilities other than those in Appendix A, then Seller shall provide Notice to Buyer identifying the facility or facilities that constitute the Project within three (3) Business Days prior to the delivery of Electric Energy from such facility or facilities in such calendar month.

8.3 Governing Law.

(a) Notwithstanding any provision to the contrary in the EEI Agreement, the Governing Law applicable to this Agreement shall be as set forth herein. This Section 8.3 does not change the Governing Law applicable to any other confirmation or transaction entered into between the Parties under the EEI Agreement.

(b) Governing Law. This agreement and the rights and duties of the parties hereunder shall be governed by and construed, enforced and performed in accordance with the laws of the state of California, without regard to principles of conflicts of law. To the extent enforceable at such time, each party waives its respective right to any jury trial with respect to any litigation arising under or in connection with this agreement.

For the purposes of Section 8.3(b) above, the words "party" and "parties" shall have the meaning ascribed to them in the preamble of this Confirmation, and the word "agreement" shall mean the term "Agreement" as defined in the preamble of this Confirmation.

ARTICLE 9
CONFIDENTIALITY

9.1 The confidentiality provisions in Section 10.11 of the EEI Agreement shall apply herein, except that each of Buyer and Seller may disclose the following information regarding this Confirmation:

(a) Party names;
(b) Resource(s);
(c) Term;
(d) Project name, location(s), and information in Appendix A;
(e) Capacity of each facility designated as the Project;
(f) The fact that a facility designated as the Project is on-line and delivering;
(g) Delivery Point;
(h) The quantity of Product expected or actually delivered under this Confirmation; and
(i) Information provided by Seller pursuant to Section 8.1 of this Confirmation

9.2 Except for disclosures to comply with any applicable regulation, rule, or order of the CPUC, Federal Energy Regulatory Commission, CEC, or other Governmental Authorities, each Party shall provide Notice of any disclosure made pursuant to this Article 9 to the other Party.

ACKNOWLEDGED AND AGREED TO BY EACH PARTY'S DULY AUTHORIZED REPRESENTATIVE OR OFFICER:

PACIFIC GAS AND ELECTRIC COMPANY, a California corporation, limited for all purposes hereunder to its electric procurement and electric fuels functions	[**BUYER, a (*include place of formation and business type*)**]
Signature: ______________________	Signature: ______________________
Name: ______________________	Name: ______________________
Title: ______________________	Title: ______________________
Date: ______________________	Date: ______________________

APPENDIX A to
EEI Master Power Purchase and Sale Agreement
Short Term Sales Confirmation

PROJECT

Name of Facility	Resource	Location	CEC RPS ID	Host Balancing Authority

APPENDIX B

FORM OF LETTER OF CREDIT

Issuing Bank Letterhead and Address

STANDBY LETTER OF CREDIT NO. XXXXXXXX

Date: [*insert issue date]*

Beneficiary:	Pacific Gas and Electric Company 77 Beale Street, Mail Code B28L San Francisco, CA 94105 Attention: Credit Risk Management	**Applicant:**	[Insert name and address of Applicant]

Letter of Credit Amount: [*insert amount]*

Expiry Date: ***[insert expiry date]***

Ladies and Gentlemen:

By order of ***[insert name of Applicant]*** ("Applicant"), we hereby issue in favor of Pacific Gas and Electric Company (the "Beneficiary") our irrevocable standby letter of credit No. ***[insert number of letter of credit]*** ("Letter of Credit"), for the account of Applicant, for drawings up to but not to exceed the aggregate sum of U.S. $ ***[insert amount in figures followed by (amount in words)]*** ("Letter of Credit Amount"). This Letter of Credit is available with ***[insert name of issuing bank, and the city and state in which it is located]*** by sight payment, at our offices located at the address stated below, effective immediately, and it will expire at our close of business on ***[insert expiry date]*** (the "Expiry Date").

Funds under this Letter of Credit are available to the Beneficiary against presentation of the following documents:

1. Beneficiary's signed and dated sight draft in the form of Exhibit A hereto, referencing this Letter of Credit No. ***[insert number]*** and stating the amount of the demand; and

2. One of the following statements signed by an authorized representative or officer of Beneficiary:

   A. "Pursuant to the terms of that certain EEI Power Purchase and Sale Agreement (the "Agreement"), dated ***[insert date of the Agreement]***, between Beneficiary and ***[insert name of Seller under the Agreement]*****,** or any Confirmation thereunder or related thereto**,** Beneficiary is entitled to draw under Letter of Credit No. ***[insert number]*** amounts owed by ***[insert name of Seller under the Agreement]*** under the Agreement; or

   B. "Letter of Credit No. ***[insert number]*** will expire in thirty (30) days or less and ***[insert name of Seller under the Agreement]*** has not provided replacement security acceptable to Beneficiary.

Special Conditions:

1. Partial and multiple drawings under this Letter of Credit are allowed;
2. All banking charges associated with this Letter of Credit are for the account of the Applicant;

3. This Letter of Credit is not transferable; and
4. The Expiry Date of this Letter of Credit shall be automatically extended without a written amendment hereto for a period of one (1) year and on each successive Expiry Date, unless at least sixty (60) days before the then current Expiry Date we notify you by registered mail or courier that we elect not to extend the Expiry Date of this Letter of Credit for such additional period.

We engage with you that drafts drawn under and in compliance with the terms of this Letter of Credit will be duly honored upon presentation, on or before the Expiry Date (or after the Expiry Date in case of an interruption of our business as stated below), at our offices at ***[insert issuing bank's address for drawings]***.

All demands for payment shall be made by presentation of original drawing documents and a copy of this Letter of Credit; or by facsimile transmission of documents to ***[insert fax number]***, Attention: ***[insert name of issuing bank's receiving department]***, with original drawing documents and a copy of this Letter of Credit to follow by overnight mail. If presentation is made by facsimile transmission, you may contact us at ***[insert phone number]*** to confirm our receipt of the transmission. Your failure to seek such a telephone confirmation does not affect our obligation to honor such a presentation.

Our payments against complying presentations under this Letter of Credit will be made no later than on the sixth (6th) banking day following a complying presentation.

Except as stated herein, this Letter of Credit is not subject to any condition or qualification. It is our individual obligation, which is not contingent upon reimbursement and is not affected by any agreement, document, or instrument between us and the Applicant or between the Beneficiary and the Applicant or any other party.

Except as otherwise specifically stated herein, this Letter of Credit is subject to and governed by the *Uniform Customs and Practice for Documentary Credits, 2007 Revision,* International Chamber of Commerce (ICC) Publication No. 600 (the "UCP 600"); provided that, if this Letter of Credit expires during an interruption of our business as described in Article 36 of the UCP 600, we will honor drafts presented in compliance with this Letter of Credit, if they are presented within thirty (30) days after the resumption of our business, and will effect payment accordingly.

The law of the State of New York shall apply to any matters not covered by the UCP 600.

For telephone assistance regarding this Letter of Credit, please contact us at ***[insert number and any other necessary details]***.

Very truly yours,

[insert name of issuing bank]

By: ______________________________
Authorized Signature

Name: ______***[print or type name]***______

Title: ______***[print or type title]***______

[Note: All pages must contain the Letter of Credit number and page number for identification purposes.]

APPENDIX B

FORM OF LETTER OF CREDIT

EXHIBIT A -- SIGHT DRAFT

TO
[INSERT NAME AND ADDRESS OF PAYING BANK]

AMOUNT: $________________________ DATE: __________________________

AT SIGHT OF THIS DEMAND PAY TO THE ORDER OF PACIFIC GAS AND ELECTRIC COMPANY THE AMOUNT OF U.S.$________ (______________ U.S. DOLLARS)

DRAWN UNDER ***[INSERT NAME OF ISSUING BANK]*** LETTER OF CREDIT NO. XXXXXX.

REMIT FUNDS AS FOLLOWS:

[INSERT PAYMENT INSTRUCTIONS]

DRAWER

BY: ________________________________
NAME AND TITLE

Appendix G

Framework for Assessing Potential Sales of Surplus RPS Volumes

~~August 20, 2018~~

March 15, 2019

Appendix G – Framework for Assessing Potential Sales of Renewables Portfolio Standard Volumes

This Appendix describes Pacific Gas and Electric Company's ("PG&E") proposed framework (the "Sales Framework") for assessing whether to hold or sell Renewables Portfolio Standard ("RPS") volumes and only applies to RPS sales with deliveries concluding within the next five calendar years~~.~~ or concluding up to 2020 until after Phase 2 of the PCIA OIR is resolved, depending on the outcome in that proceeding. This Appendix G framework governs only PG&E's 2019 Bundled RPS Energy Solicitations. For purposes of clarity, Appendix J to this Plan, which governs other sales of Tree Mortality Non-Bypassable Charge Renewable Energy Credits, does not apply to the 2019 Bundled RPS Energy Solicitation. This Sales Framework will be updated each year as part of the RPS Plan filing. PG&E may therefore annually adjust its methodology and the resulting calculations of volumes for sale.

[redacted]

[redacted]

[redacted][1]

---

[1] [redacted]

[redacted][2] [redacted]

[redacted]

[redacted]

1. [redacted][3]
2. [redacted]
3. [redacted][4]

[redacted]

[redacted]

---

2 PG&E may issue more than three solicitations per year. The exact timing and number of solicitations is dependent upon the outcome of prior solicitations and/or changes to PG&E's RPS position.

3 PG&E uses the phrase "historical long position" to refer to volumes in its existing Bank plus historical RPS volumes that have generated above the annual RPS compliance targets in a current compliance period.

4 [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]

- [redacted]
- [redacted]

APPENDIX H

Detailed Explanation of PG&E's Least-Cost, Best-Fit Methodology

~~August 20, 2018~~March 15, 2019

PG&E's Description of its RPS Bid Evaluation, Selection Process and Criteria

I. Introduction

A. Establishment of the Least-Cost, Best-Fit (LCBF) Process

Decision D.03-06-071 and D.04-07-029 adopted criteria for the rank ordering and selection of least cost, best fit renewable resources for use in RPS solicitations. Furthermore, D.05-07-039 directed the IOUs to make their bid evaluation process transparent to their Procurement Review Groups (PRG) and the California Public Utilities Commission (CPUC).

In addition, D.06-05-039 required "each utility to provide a report when it submits its short list of bids. Each utility should also serve a copy on the service list, and make the report available to the fullest extent possible to any other person or party expressing interest, subject to confidential treatment of protected information. The report shall explain each utility's evaluation and selection model, its process, and its decision rationale with respect to each bid, both selected and rejected."

D.06-05-039 also required each IOU to hire an Independent Evaluator ("IE") "to separately evaluate and report on the IOU's entire solicitation, evaluation and selection process for this and all future solicitations. This will serve as an independent check on the process and final selections. The Independent Evaluator's preliminary report should be provided with the IOU's shortlist, and a final report with the AL for approval of selected bids."

The Scoping Memo for R.06-05-027, issued August 21, 2006, required that the IOUs submit their first written report describing their bid evaluation criteria and selection process on September 29, 2006, and that IOUs resubmit the report with their short lists (including more information, such as bid analysis, as necessary). Additionally, in the RPS Transparency Workshop held on December 15, 2006, the CPUC's Energy Division staff proposed, pursuant to D.06-05-039, a template to be used for future evaluation criteria and selection reports ("LCBF Written Report").

D.06-05-039 further required that each IOU include certain elements, subject to confidential treatment of protected information, in each report. These elements include bid-specific price information, the evaluation and scoring of each bid, and the decision rationale with respect to each bid, both selected and rejected. D.11-04-030 added that each utility should describe LCBF treatment of congestion, and to certain price data available. Although PG&E's 2018 RPS Plan does not indicate a need for RPS procurement, PG&E's LCBF protocol may be used in other RFOs for mandated procurement or for RPS energy sales.

B. Goal of PG&E's bid evaluation, selection criteria, and processes

The goal of the bid evaluation, selection criteria, and selection processes is to produce a short list of offers for negotiations consistent with the procurement goals set forth in an RFO.

II. Bid Evaluation and Selection Criteria

A. Overview of the Ranking Methodology

PG&E evaluates each bid in terms of the following quantitative and qualitative attributes:

1. Net Market Value
    a. Benefits (Energy, Capacity, REC, Ancillary Services)
    b. Contract Payments
    c. Transmission Network Upgrade Costs (also called a "transmission adder")
    d. Congestion Cost
2. Portfolio-Adjusted Value
    a. RPS Portfolio Need

3. Qualitative factors

Solicited bids are evaluated using the following step-by-step process:

The Net Market Value (NMV) is computed for each Offer. NMV will be adjusted by other attributes, such as RPS portfolio need, to arrive at the Portfolio-Adjusted Value (PAV). After the calculation of PAV is complete, PG&E considers qualitative criteria listed below. The set of highest ranked Offers which allow for a reasonable probability of satisfying PG&E's procurement goal is selected for the Shortlist or contract execution.

1. Market Valuation

a. Overview of the Market Valuation Criterion

Market valuation considers how an Offer's costs compare to its market benefits. Costs include Transmission Network Upgrade Cost, Congestion Cost and Integration Cost as well as contract payments. Benefits include energy, capacity, and ancillary services values. Specifically, Market Valuation computes NMV for each offer as follows:

$$\text{Net Market Value: } R = (E + C) - (P + T + G + I)$$
$$\text{Adjusted Net Market Value: } A = R + S$$

Where
E = Energy Value
C = Capacity Value
P = Post-Time-Of-Delivery (TOD) Adjusted Power Purchase Agreement (PPA) Price
T = Transmission Network Upgrade Cost
G = Congestion Costs
I = Integration Costs

S = Ancillary Service Value

Costs and Benefits are each quantified and expressed in terms of levelized dollars per MWh. NMV is Benefits minus Costs, and is expressed in terms of levelized dollars per MWh.

The calculation of Benefits, Costs, and Market Value is described below.

b. Calculation of Benefits and PPA Costs

Energy benefit (E), for each hour of delivery, is the value of energy delivered at the market energy price at the corresponding Trading Hub (NP15, SP15, ZP26, Palo Verde), adjusted for Losses, plus the market value of the renewable attribute. As-available (or must-take) energy delivery for each hour from an Offer is determined by the hourly generation profile of the Offer. To the extent that the Offer provides dispatchable capacity, the value of the option from the dispatchability will be captured in the energy benefit calculation. The option value calculation depends on the particular characteristics of the dispatchable capacity. If an Offer includes energy storage that allows PG&E to schedule the discharge and charge of the storage, the energy benefit will also include the additional value that PG&E can realize from being able to shift the RPS energy from the Project to more valuable hours given the constraints of the energy storage.

Losses vary by location of the project and are assessed using the Locational Marginal Price (LMP). The Loss Multiplier for a project delivered to Palo Verde will be 100%. The average Loss Multipliers for a project delivered to CAISO are provided in Table 1. A higher Loss Multiplier implies less loss, thus more value associated with a project located in the corresponding load zone. PG&E may further update the Loss Multipliers based on updated market conditions.

Discounted hourly energy benefit is summed across hours of delivery, and summed across years. The total benefit is then scaled by the delivered energy to be expressed in terms of levelized dollars per MWh.

For offers providing Buyer Curtailment, **energy benefit** will include the option value of the difference between the (presumably negative) wholesale market spot price avoided for the Project and PG&E's cost when Buyer Curtailment occurs.

Capacity benefit (C) for Resource Adequacy (RA), for year of availability, is the projected monthly quantity of qualifying capacity multiplied by the projected monthly capacity price, discounted and summed across years. To the extent that an Offer provides flexible capacity, the capacity that is expected to count for flexible RA and provide the ISO's must-offer requirement for flexible capacity resources will be evaluated at the projected monthly premium (which can be zero or positive) for flexible RA and then added to the Capacity Benefit. There currently exists significant uncertainty regarding the specifics of generic and flexible RA markets in California.

Therefore, the calculation of capacity benefit may evolve as more information is known about market design or as uncertainty lingers.

For an Offer in a location that is projected to contribute to PG&E's satisfaction of a Local Capacity Requirement, the capacity attributable to the Offer may be valued at a premium relative to the value of capacity that satisfies only system needs.

Ancillary Services benefit (S) is assumed to be zero if an Offer doesn't provide any Ancillary Services (A/S) capability. For Offers that provide PG&E the ability to schedule Ancillary Services, the incremental benefit of having A/S capability will be captured, not to be double counted with the energy benefit.

PPA Payments (P) are determined by the expected payments under each Offer including associated debt equivalence costs. The PPA Payment for each hour is calculated by multiplying expected delivery quantity by the Offer's price. The Offer's price is the contract price of the Offer multiplied by the applicable Time of Delivery (TOD) factors specified in the RPS Solicitation Protocol. The hourly PPA Payment is expressed in units of levelized dollars per MWh.

c. Calculation of Transmission Network Upgrade Costs

The Transmission Network Upgrade Costs (T) is the cost, if any, of bringing the power from the generating facility to PG&E's network. PG&E expects to use results from Participants' interconnection studies.

A Present Value Revenue Requirement (PVRR) is calculated from the Interconnection Study for each evaluated bid. If the Seller is offering an energy-only resource, PG&E will use the reliability network upgrades identified in the interconnection study for calculation of the transmission adder. If the Seller is offering a full deliverability resource, PG&E will use both the reliability network upgrades and delivery network upgrades in the calculation. If the resource does not have an interconnection study, PG&E may rely on a cost cap for transmission upgrades proposed by the Participant.

The PVRR captures from a ratepayer perspective the risk and cost to construct and maintain transmission upgrades to accommodate the generation from the renewable resource.

This PVRR of the costs of the Network Upgrades is converted into levelized dollars per MWh.[1]

PG&E may take into account on a qualitative basis the additional value for projects that have no transmission risk.

[1] Sellers offering full capacity offers may specify when full capacity is to begin and as a result, costs will be reflected accordingly in the PVRR calculation.

d. Congestion Costs

Congestion cost (G) for each hour is calculated by the multiplication of (1) a Congestion Cost Multiplier for the corresponding time period and load zone, (2) the Locational Marginal Price (LMP) of the corresponding Trading Hub, and 3) expected energy delivery.

A project delivered to Palo Verde would be evaluated with Congestion Cost of 0%. A summary of Congestion Cost Multipliers for each load zone in CAISO is included in Table 1. A higher Congestion Cost Multiplier indicates a higher Congestion Cost (G). Specifically, a Congestion Cost Multiplier greater than zero indicates that generation in the corresponding area serves load outside of the area by congested lines and thus a new generation in the corresponding area is expected to increase the congestion. A zero Congestion Cost Multiplier implies there is no congestion in the transmission lines connecting the area. A Congestion Cost Multiplier less than zero indicates that loads in the corresponding area are served by the constrained transmission line(s) and thus a new generation in the area may reduce congestion. PG&E may update the Congestion Cost multipliers as market prices change.

TABLE 1
Congestion Cost Multipliers and Loss Multipliers[2]

			Loss Multipliers		Congestion Cost Multipliers		LMP Multipliers	
			for E		for G		for E-G	
	Descriptive Names	CAISO	On Peak	Off Peak	On Peak	Off Peak	On Peak	Off Peak
1	PG&E Central Coast	PGCC	102.4%	100.5%	2.2%	1.6%	100.2%	98.9%
2	PG&E East Bay	PGEB	101.9%	99.9%	2.1%	1.4%	99.8%	98.5%
3	PG&E Fresno	PGF1	103.1%	102.7%	-2.3%	-6.4%	105.4%	109.0%
4	PG&E Fulton	PGFG	101.5%	98.6%	2.7%	1.3%	98.8%	97.3%
5	PG&E Humboldt	PGHB	103.8%	104.2%	2.6%	2.0%	101.2%	102.2%
6	PG&E Los Padres	PGLP	100.1%	98.3%	3.0%	1.9%	97.0%	96.3%
7	PG&E North Bay	PGNB	102.0%	99.5%	2.8%	1.4%	99.2%	98.0%
8	PG&E North Coast	PGNC	103.0%	98.5%	4.8%	3.6%	98.2%	95.0%
9	PG&E North Valley	PGNV	98.0%	97.4%	2.3%	0.9%	95.7%	96.5%
10	PG&E Peninsula	PGP2	103.0%	100.7%	2.7%	1.3%	100.3%	99.4%
11	PG&E Sacramento	PGSA	100.4%	99.3%	1.8%	0.9%	98.6%	98.4%
12	PG&E South Bay	PGSB	102.6%	100.6%	2.5%	1.2%	100.1%	99.3%
13	PG&E San Francisco	PGSF	104.8%	101.6%	1.7%	1.3%	103.1%	100.3%
14	PG&E Sierra	PGSI	99.9%	99.1%	1.1%	0.9%	98.8%	98.2%
15	PG&E San Joaquin	PGSN	96.7%	96.4%	2.8%	1.4%	93.9%	95.0%
16	PG&E Stockton	PGST	101.0%	99.8%	2.7%	1.4%	98.3%	98.5%
17	So Cal Edison Core	SCEC	96.9%	98.7%	-1.6%	-0.6%	98.5%	99.3%
18	So Cal Edison North	SCEN	96.4%	99.4%	-5.8%	-2.9%	102.2%	102.2%
19	So Cal Edison West	SCEW	98.9%	100.1%	-3.7%	-1.0%	102.6%	101.1%
20	So Cal Edison High	SCHD	92.8%	95.2%	-0.5%	-0.9%	93.3%	96.1%
21	So Cal Edison Low	SCLD	96.0%	97.7%	0.2%	-0.8%	95.8%	98.4%
22	So Cal Edison North	SCNW	96.6%	98.7%	-0.5%	-0.9%	97.1%	99.6%
23	San Diego Gas &	SDG1	99.0%	99.7%	-2.6%	-0.3%	101.7%	100.1%

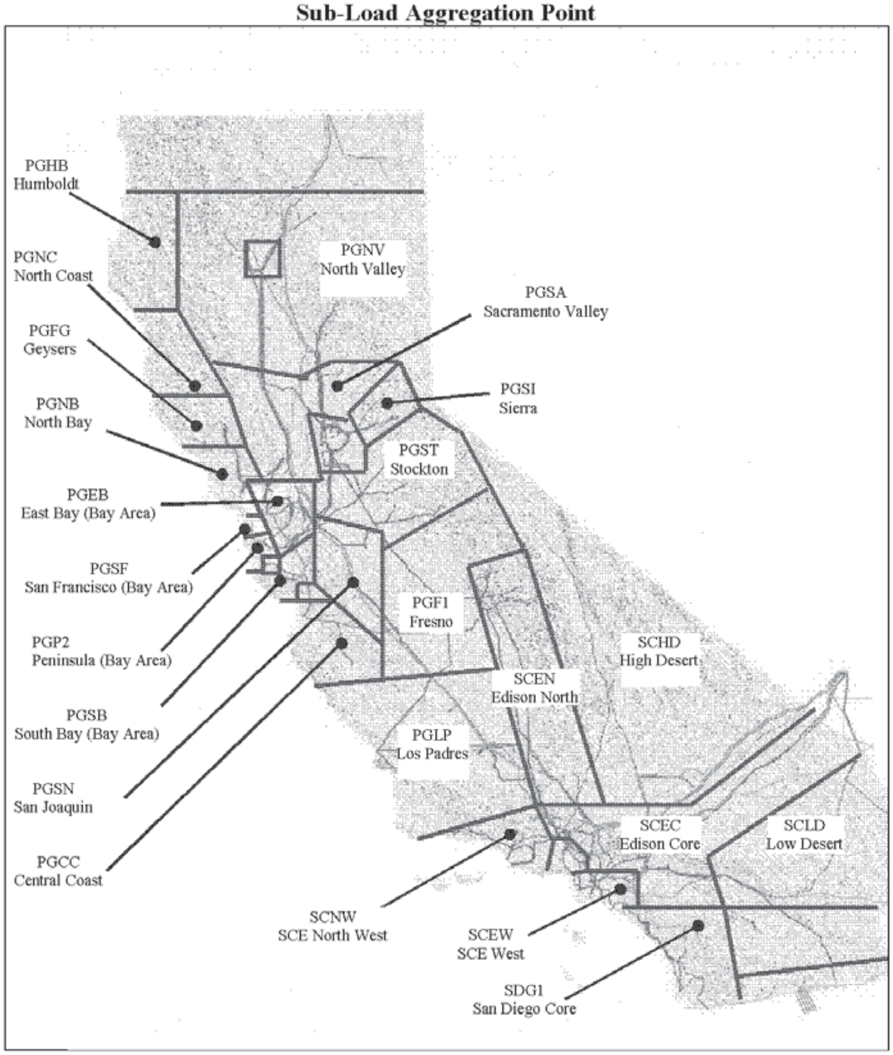
Overall locational value of the project delivered to CAISO should be assessed by looking at the LMP multipliers provided in Table 1. LMP Multiplier for a project delivered to Palo Verde will be 1. The LMP multipliers imply the relative value of 1 MWh in each load zone compared with the corresponding Trading Hub (NP15, SP15, ZP26, or Palo Verde) price. For example, PG&E could consider Offer A located in Sierra and Offer B located in San Francisco, with everything else the same. Offer B will have higher Energy Value (E) because the Loss Multipliers in San Francisco are higher than for the Sierra. On the other hand, Offer A has lower Congestion Cost (G) because the

[2] Multipliers shown are a simple average over hours and months. Contract valuations use disaggregated values for different months.

Congestion Cost Multiplier for Sierra is lower than San Francisco. Overall, Offer B scores higher than Offer A, because E-G will score higher due to higher LMP Multipliers in San Francisco compared with Sierra.

The map for CAISO APNodes is for illustrative purposes only.

Sub-Load Aggregation Point



e. Integration Costs

The renewable integration cost adder (RICA) is calculated using the methodology adopted in D.14-11-042. Renewable integration cost is used in the derivation of Net Market Value per Section 1.a of this document.

The RICA is calculated as the sum of two cost components: 1) variable costs; and 2) fixed costs.

The variable cost component is set at $4/MWh for wind and $3/MWh for solar.

The fixed cost component is calculated as the product of two parameters: 1) PG&E's internal/confidential projection of a monthly premium (which can be zero or positive) for flexible RA expressed as $/kW-month; and 2) the monthly increase (or decrease) in the need for flexible RA associated with one MW of installed capacity of wind or solar ("Contribution to Flexible Capacity Needs") expressed as MW of flex capacity needed/MW of wind or solar capacity.

The Contribution to Flexible Capacity Needs is determined in the following way:

1. Obtain the hourly aggregate system profile for load, wind, and solar.[3]
2. Calculate the hourly three hour net-load ramp for each hour of the year.[4]
3. Identify the maximum three hour net-load ramp for each month, and determine the relative contributions from load, wind, and solar to that ramp.
4. Determine the monthly increase (or decrease) in the need for flexible capacity associated with one MW of installed capacity of wind and solar. This is determined based on the contribution of wind / solar in step 3 and the total installed capacity of wind / solar in the system. For example, if there is 5,000 MW of installed wind and wind's contribution to the maximum three hour net-load ramp in July is 500 MW, then wind's contribution to flexible capacity need is 500 MW / 5,000 MW, or 0.1 MW per 1 MW of installed wind. In this example, 0.1 MW would be the Contribution to Flexible Capacity Needs attributed to a bid for wind generation expected to deliver in that month.

For 2018, PG&E has calculated the Contribution to Flexible Capacity Needs using the four steps above and hourly data from the 2014 Long Term Procurement Plan (LTPP) Trajectory Scenario[5]. The maximum (single hour) wind / solar output from these 2014 LTPP hourly data is used to estimate the total installed capacity for wind / solar in the system. The resulting Contribution to Flexible Capacity Needs for solar and wind are presented in Table 2 below. These numbers may be updated based on supply and demand information adopted in the most recent Integrated Resource Plan (IRP).

[3] Consistent with the CAISO Flexible Capacity Study, the solar PV and solar thermal components are combined. (http://www.caiso.com/Documents/Final_2014_FlexCapacityNeedsAssessment.pdf)

[4] Consistent with the CAISO Flexible Capacity Study, this is the three hour contiguous ramp starting in a given hour of the year, where net-load is defined as load minus wind minus solar

[5] The hourly data can be obtained from the results of the CAISO's 2014 LTPP Production Cost runs. The CAISO posted these results on its LTPP File Transfer Protocol (FTP) website at http://12.200.60.146:990 on July 31, 2014. To help parties access this information, PG&E is also providing these publicly available hourly profiles on its website at www.pge.com/rfo under 2014 Renewables RFO.

TABLE 2
Contribution to Flexible-RA Requirement Per 1 MW of Installed Capacity (MW)

Month	Solar	Wind
JAN	0.52	0.12
FEB	0.75	0.09
MAR	0.63	0.15
APR	0.78	0.13
MAY	0.66	0.01
JUN	0.58	0.07
JUL	0.58	0.04
AUG	0.61	0.05
SEP	0.78	0.20
OCT	0.66	0.02
NOV	0.59	0.00
DEC	0.63	0.20

f. Market Valuation for Offers with Storage

PG&E evaluates the market value from dispatchable storage bundled in an Offer for its ability to (1) shift renewable energy to more valuable hours, (2) provide A/S from stored energy and storage capacity, and (3) provide flexible RA.

PG&E solves for the charge, discharge and A/S schedules that would maximize the value from the project starting from the generation profile without using the energy storage, and the storage constraints provided by the Seller. In order to maximize the spot market value from the project given the assumed market prices for energy and A/S, PG&E will use an optimization technique to obtain the best time and amount to charge, discharge and provide A/S capacity. The spot market value consists of the revenue from energy to be delivered to the grid (the sum of energy that is directly generated from the renewable resource and the energy discharged from storage) and the revenue of A/S capacity to be provided, net of the variable cost from operating. Depending on the energy and A/S prices for a given time period, it may be better to provide A/S, charge renewable energy, discharge stored energy, or do nothing from storage. The Energy Value, A/S Value and PPA Costs in Net Market Value are computed from the assumed market prices as well as the optimized charge, discharge, generation, and A/S schedules.

For Ancillary Services, PG&E asks bidders to specify capability, ramp rates and operating ranges for providing Regulation Up and Down, Spinning Reserve (Spin) and Non-spinning Reserves (Non-spin). When optimizing the schedules, PG&E makes sure that the A/S schedules are within the operating ranges provided and that there is enough energy and storage capacity available. For valuation purposes, PG&E will assume that the value from providing Non-spin in addition to the Spin is negligible because the price for Non-spin is never higher than price for a similar Spin product.

PG&E may include future CAISO A/S products such as flexible ramping product in an optimization to estimate their value if PG&E anticipates that there could be significant incremental value.

Dispatchable storage components that can follow CAISO's day-ahead and real-time dispatch instructions and thus allow PG&E to provide economic bids are expected to count towards meeting PG&E's requirement for flexible RA. Due to the uncertainty about the counting rules that will govern co-located storage components, PG&E will estimate Effective Flexible Capacity (EFC) for renewable offers with storage as a function of MW size and discharge duration of the energy storage component. The calculation of capacity benefit may evolve as more information is known about market rules. The flexible RA Value will be included in the Capacity Value of the Net Market Value.

2. Portfolio Adjusted Value

Portfolio Adjusted Value (PAV) adjustments reflect PG&E's portfolio position and the value to PG&E's portfolio of a purchase or sale.

a. RPS Portfolio Need

PG&E will consider how an Offer contributes to PG&E's overall portfolio need for RPS energy. For a delivery year in which PG&E's portfolio (augmented by the offer) is projected to have lower or higher than targeted RPS-eligible energy, then the PAV Adjustment for the Offer's RPS-eligible energy may be adjusted to a higher or lower value to aid in meeting PG&E's RPS eligible energy targets.

This RPS Portfolio Need adjustment is not duplicative of the Energy Value component of Net Market Value.

Thus, Offers that deliver RPS energy only in periods when PG&E's portfolio needs RPS energy will have higher PAV and rank better than equivalent offers that deliver RPS energy in periods when PG&E's portfolio is long.

3. Qualitative Factors

PG&E may consider qualitative factors including but not limited to:

- Project location in PG&E's service territory
- Project viability: As part of its qualitative assessment of project viability, PG&E will calculate a project viability score using the most recent version of the Project Viability Calculator adopted by the CPUC.
- Impact on disadvantaged communities
- Water use and impact on water quality
- Contribution to state biomass goals
- Contribution to storage targets
- Mark-up of term sheet or PPA
- Contract tenor

- Counterparty concentration
- Technology diversity
- Previous experience with counterparty
- Safety

APPENDIX J

Framework for the Tree Mortality Non-Bypassable Charge Renewable Energy Credit Sales Solicitation

March 15, 2019

Appendix J – Framework for the Tree Mortality Non-Bypassable Charge Renewable Energy Credit Sales Solicitation

This Appendix is included in PG&E's Renewable Energy Procurement Plan (the "RPS Plan") in order to describe its framework for the sale of Renewable Energy Credits ("RECs") associated with certain Renewables Portfolio Standard ("RPS")-eligible biomass generation contracts (the "TM RECs"), in compliance with Ordering Paragraph 4 of California Public Utilities Commission ("Commission") Decision ("D.") 18-12-003. The Appendix contains the following:

- A summary of D.18-12-003's requirements with respect to the sale of specific RECs
- The framework that PG&E will use in order to comply with D.18-12-003

This Appendix J framework governs only PG&E's Tree Mortality Non-Bypassable Charge ("TM NBC") REC Sales Solicitation. For purposes of clarity, Appendix G to this Plan, which governs other sales of RPS-eligible products, does not apply to the TM NBC REC Sales Solicitation except as specifically incorporated by reference in this Appendix J.

I. Decision Summary

On December 21, 2018 the Commission issued D. 18-12-003 establishing a methodology for calculating a non-bypassable charge for costs associated with certain tree mortality biomass energy procurement. The non-bypassable charge will recover the net costs of the mandated biomass energy procurement intended to address California's tree mortality crisis. Of particular relevance to this RPS Plan, the Decision requires that PG&E establish a value for the TM RECs by making them available for sale.[1]

II. Compliance Requirements

With regard to the sale of the TM RECs, the Decision orders PG&E to:

- Make available for sale the TM RECs associated with its tree mortality-related procurement contracts required by Resolution E-4770 and Resolution E-4805 as soon as possible after the effective date of the Decision;[2]
- File any executed sales for the TM RECs associated with its tree mortality-related procurement contracts via Tier 1 advice letters so long as it (1) utilizes the Commission-approved RPS Sales pro forma agreement and (2) shows modifications via a comparison document;[3]
- Repeat this process if its tree mortality contracts are extended;[4] and

[1] D.18-12-003, pp. 25-26 (Ordering Paragraph ("OP") 3).
[2] *Id.*, pp. 25-26 (OP 3).
[3] *Ibid.*
[4] *Ibid.*

- Update its final, conforming version of its 2018 RPS Plan to conform to the REC sales requirements set forth in D.18-12-003.[5]

As part of a separate Advice Letter filing, PG&E is required to design and implement the TM NBC, in which it must deduct the appropriate REC values from the total costs of its TM contracts.[6]

IV. PG&E's TM REC Sales Framework

To comply with the decision, PG&E will launch its TM NBC REC Sales Solicitation to make available for sale the TM RECs as soon as possible after the Final, Conforming Version of the 2018 Renewable Portfolio Standard Plan is submitted. PG&E will use the solicitation protocol in Appendix F.1, making any necessary modifications prior to solicitation launch to conform to this framework. PG&E will also make necessary modifications to its Commission-approved pro forma sales agreement in Appendix F.3 to conform to this framework and to address issues raised in specific negotiations with counterparties. Consistent with the Decision, PG&E will file any executed sales of TM RECs via Tier 1 Advice Letter and show modifications to the approved pro forma agreement via a comparison document. PG&E will engage an Independent Evaluator ("IE") to provide oversight of the TM NBC REC Sales Solicitation process. The IE's report will be included in the Tier 1 Advice Letter filed following the TM NBC REC Sales Solicitation.

PG&E will value TM RECs based upon the result of the TM NBC REC Sales Solicitation and deduct that amount from the TM NBC. In the event that the TM NBC REC Sales Solicitation does not result in a sale of any TM RECs, PG&E will not use the unsold TM RECs for compliance and the value deducted from the TM NBC will be $0.[7]

To the extent that a contract with a third-party results from a TM NBC REC Sales Solicitation and the third-party defaults on the contract prior to expiration resulting in termination of the contract, PG&E will expeditiously conduct another TM NBC REC Sales Solicitation for the remaining term of the original agreement, provided that PG&E determines a subsequent solicitation would not take longer than the remaining term of original agreement, and value the remaining RECs in the TM NBC based upon the result of that Solicitation. PG&E will elect to use any TM NBC RECs that are generated but cannot be transferred due to the default of the original counterparty for its own RPS compliance and value the RECs in the TM NBC at the same price executed in the original third-party agreement until a new contract for the remaining term goes into effect and begins delivering.

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[5] *Id.*, p. 27 (OP 4).
[6] *Id.*, pp. 25-26 (OP 3), p. 30 (OP 11).
7 D.18-12-003 provides in OP 3: "If the RECs are not purchased, then the value deducted shall be $0 and no load-serving entity may use the REC for compliance purposes." While D.18-12-003 requires PG&E to use a $15.04/MWh price if a REC "was offered for sale in the past, not sold, and then used by the IOU for compliance purposes," the use of the phrase "in the past," which does not appear in a similar framework for TM RA sales set forth in the Decision, makes clear that going forward, unsold RECs have no compliance value. See id., pp. 12-13 (describing REC sales framework); pp. 18-19 (describing RA sales framework).

If PG&E later determines that modifications to this framework are necessary, including changes resulting from any tree-mortality contract extensions pursuant to Section 8388 of the California Public Utilities Code, it will file all modifications via Tier 1 Advice Letter or through the regular RPS Plan cycle.

The following subsections provide additional details on the TM NBC REC Sales Solicitation structure.

A. PG&E's Tree Mortality Biomass Contracts Subject to the TM NBC[7]

Facility Name	Contract Capacity (MW)	Initial Energy Delivery Date	Expected Delivery End Date
Burney Forest Products	29	11/1/2017	10/31/2022
Wheelabrator Shasta	34	12/2/2017	12/1/2022

B. Product Structure

Product Structure for TM NBC REC Sales Solicitation	
Product	• Bundled RPS-energy and associated RECs from PG&E's TM PPAs listed in the table above[8]
Pricing	• Energy – settled at the market index price[9] • REC – fixed price
Delivery Term	• Solicitation #1: Residual term of the tree mortality contracts prior to any extensions (< 5 years) • Solicitation #2 (if needed): Any extended terms of tree mortality contracts executed pursuant to Section 8388 of the California Public Utilities Code (up to 5 years)[10]
Quantity	• Unit-specific - Buyer receives future full energy and REC output of the underlying tree mortality contract
Agreement	• Utilize the Commission-approved RPS sales pro forma agreement (executed contract filed as part of Tier 1 AL in both clean and redline to shows changes to the pro forma agreement)[11]

C. Evaluation Criteria

Quantitative – Select bids based on price (highest price in $/MWh)
Qualitative – Consistent with qualitative criteria defined in Appendix F.1 to this RPS Plan (the Bundled RPS Solicitation Protocol).

[7] Any facilities that receive contract extensions pursuant to California Public Utilities Section 8388 would be sold through a separate solicitation following those contract extensions. Implementation of Section 8388 may add to and otherwise modify the list of facilities referenced in this table.
[8] D.18-12-003, p. 26 (OP 3, bullet 1).
[9] *Ibid.*
[10] *Id.*, p. 26 (OP 3, bullet 4).
[11] *Id.*, p. 26 (OP 3, bullet 2).

[redacted]

D. Proposed Solicitation Issuance

As soon as possible following acceptance of Final 2018 RPS Plan.