Decision 19-02-007 February 21, 2019

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

DECISION ACCEPTING DRAFT 2018 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

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DECISION ACCEPTING DRAFT 2018 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

Summary

Pursuant to the authority provided in Pub. Util. Code § 399.13(a)(1),[1] today's decision accepts the draft 2018 Renewables Portfolio Standard (RPS) Procurement Plans, if modified in accordance with this Decision, including the related solicitation protocols, filed by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

The request of PG&E, SCE, and SDG&E to forgo holding a 2018 RPS solicitation is approved. We direct PG&E, SCE, and SDG&E to file final 2018 RPS Procurement Plans pursuant to the schedule adopted herein. No incremental procurement beyond existing RPS mandates is ordered in this decision.

This decision authorizes PG&E, SCE, and SDG&E to conduct solicitations for sales of RPS volumes if the pro forma sales agreement for any such sale is executed during the timeframe covered by the 2018 RPS Procurement Plans, or prior to the Commission issuing a decision on the 2019 RPS Procurement Plans. Deliveries under any such sales agreement shall be for a delivery term of five years or less, and may commence at any time prior to the Commission issuing a decision on the 2019 RPS Procurement Plans and continue until the expiration of the agreement's term. PG&E, SCE, and SDG&E must seek Commission approval

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[1] Pub. Util. Code § 399.13(a)(1) orders the Commission to "direct each electric corporation to annually prepare a renewable energy procurement plan…to satisfy its obligations under the renewables portfolio standard," as well as "require other retail sellers to prepare and submit renewable energy procurement plans…" All subsequent code section references are to the Public Utilities Code unless otherwise indicated.

of sales resulting from a solicitation or any bilateral transaction that both utilizes the pro forma sales agreement submitted with the investor-owned utility's (IOU) 2018 RPS Procurement Plan and is executed after the IOU receives bids for a sales solicitation resulting from its 2018 RPS Procurement Plan. This decision also approves the request of PG&E, SCE, and SDG&E to engage in bilateral sales transactions that do not utilize the pro forma sales agreement submitted with the IOU's 2018 RPS Procurement Plan or that are not executed after the IOU receives bids for a sales solicitation resulting from its 2018 RPS Procurement Plan, subject to the Commission's review and approval. Liberty Utilities (CalPeco Electric) draft 2018 Renewables Portfolio Standard (RPS) Procurement Plan is also accepted, if updated in accordance with this decision, and Liberty Utilities is authorized to procure RPS-eligible resources.

This decision also accepts the draft 2018 RPS Procurement Plans filed by the following retail sellers of electricity that are subject to California's RPS program:

Small and Multi-jurisdictional Utilities: Bear Valley Electric Service and PacifiCorp.

Community Choice Aggregators: Redwood Coast Energy Authority, Apple Valley Choice Energy, Marin Clean Energy, Pico Rivera Innovative Municipal Energy, Silicon Valley Clean Energy, Sonoma Clean Power Authority, Peninsula Clean Energy, CleanPowerSF, Lancaster Choice Energy, Valley Clean Energy, Monterey Bay Community Power, San Jacinto Power, Rancho Mirage Energy Authority, Clean Power Alliance of Southern California, East Bay Community Energy, Pioneer Community Energy, Solana Energy Alliance, San Jose Community Energy, Desert Community Energy, and King City.

Electric Service Providers: 3 Phases Renewables, Agera Energy, LLC, American PowerNet Management, LP, Calpine PowerAmerica-CA, LLC, Calpine Energy Solutions, LLC, Commerce

Energy of Montana, Inc. (dba Commercial Energy of California), Constellation NewEnergy, Inc., Direct Energy Business LLC, Direct Energy Services, LLC, EDF Industrial Power Services (CA), LLC, EnerCal USA, LLC (dba Yep Energy, Y.E.P.), Gexa Energy California, LLC, Just Energy Solutions, Inc., Liberty Power Holdings, LLC, Pilot Power Group, Inc., Shell Energy North America (US), L.P., The Regents of the University of California, and Tiger Natural Gas, Inc.

This proceeding remains open.

1. Background

The Commission has adopted a framework for consideration of Renewables Portfolio Standard (RPS) Procurement Plans for electric corporations and other RPS obligated retail sellers in prior decisions. The definition of "retail seller" in Public (Pub.) Utilities (Util.) Code § 399.12(j) includes the electrical corporations, as defined in Pub. Util. Code § 218, community choice aggregators (CCAs) and electric service providers (ESPs). The most recent decision is Decision (D.) 17-12-007.[2] Consistent with the general process referred to in D.17-12-007, other prior Commission decisions, and the requirements in Senate Bill (SB) 350[3] and SB 100,[4] the parties were required to file their proposed RPS Procurement Plans for 2018 and to set forth the information required therein.

On June 21, 2018, the assigned Commissioner and assigned Administrative Law Judge (ALJ) issued a ruling *Identifying Issues and Schedule of Review for 2018*

[2] *Decision Accepting Draft 2017 Renewables Portfolio Standard Procurement Plans* (December 14, 2017). In D.17-12-007, the Commission adopted 2017 RPS Procurement Plans.

[3] SB 350 (De Leon, Stats. 2015, ch.547).

[4] SB 100 (De Leon, Stats. 2018, ch. 312).

Renewables Portfolio Standard Procurement Plans and Inviting Comments on Renewable Auction Mechanism Proposal [*2018Assigned Commissioner Ruling (ACR)*]. The retail sellers below submitted draft 2018 RPS Procurement Plans on or before August 20, 2018, after an extension of time requested by Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), and Pacific Gas and Electric Company (PG&E) was granted by the ALJ. These retail sellers also submitted updates to the 2018 RPS Procurement Plans on or before October 8, 2018 in response to the Administrative Judges' Ruling[5] to update 2018 RPS Procurement Plans to address changes necessitated by SB 100:

> <u>Investor-Owned Utilities (IOUs)</u>: SCE,[6] SDG&E, and PG&E.
>
> <u>Small and Multi-jurisdictional Utilities (SMJU)</u>: Bear Valley Electric Service (BVES), Liberty Utilities (CalPeco Electric), and PacifiCorp.
>
> <u>Community Choice Aggregators (CCAs)</u>: Redwood Coast Energy Authority, Apple Valley Choice Energy, Marin Clean Energy, Pico Rivera Innovative Municipal Energy, Silicon Valley Clean Energy, Sonoma Clean Power Authority, Peninsula Clean Energy, CleanPowerSF, Lancaster Choice Energy, Valley Clean Energy, Monterey Bay Community Power, San Jacinto Power, Rancho Mirage Energy Authority, Clean Power Alliance of Southern California, East Bay Community Energy, Pioneer Community Energy, Solana Energy Alliance, San Jose Community Energy and King City.
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> <u>Electric Service Providers (ESPs)</u>: 3 Phases Renewables, Agera Energy, LLC,[7] American PowerNet Management, LP, Calpine PowerAmerica-CA, LLC, Calpine Energy Solutions, LLC, Commerce

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[5] E-mail Ruling sent out by Judge Robert Mason on September 19, 2018 ordered all IOUs, CCAs, and ESPs to serve updates to their Draft 2018 Renewable Portfolio Standard Procurement Plans to address SB 100.

[6] SCE submitted a *Motion to Further Update its 2018 RPS Procurement Plans* on November 2, 2018.

[7] Agera Energy, LLC late filed its RPS Plan on July 31, 2017.

Energy of Montana, Inc. (dba Commercial Energy of California), Constellation NewEnergy, Inc., Direct Energy Business LLC, EDF Industrial Power Services (CA), LLC, EnerCal USA, LLC (dba Yep Energy, Y.E.P.), Gexa Energy California, LLC, Just Energy Solutions, Inc., Liberty Power Holdings, LLC, Pilot Power Group, Inc., Shell Energy North America (US), L.P., The Regents of the University of California, and Tiger Natural Gas, Inc.

The following parties did not file RPS procurement plans but have been granted the relief requested in their *Motions for Provisional Waiver from Future RPS Compliance Reports* in D.13-11-024: Liberty Power Delaware LLC and Praxair Plainfield, Inc.

The following party filed *Motion for Provisional Waiver from Future RPS Compliance Reports*: Palmco Power CA (filed July 10, 2018).[8]

1.1. Assigned Commissioner Ruling

As mentioned above, on June 21, 2018, the assigned Commissioner and assigned ALJ issued a ruling setting the reporting requirements and schedule for the 2018 RPS procurement planning process (*2018 ACR*). The following parties filed comments on the RPS Procurement Plans on September 21, 2018: American Wind Energy Association California Caucus (ACC), Green Power Institute (GPI), Independent Energy Producers Association (IEPA), PG&E, SCE and SDG&E (Joint IOUs), L. Jan Reid, Large-Scale Solar Association (LSA), and Public Advocates Office.

The following parties filed reply comments on October 5, 2018: California Energy Storage Alliance (CESA), City and County of San Francisco, Alliance for Retail Energy Markets (AReM), and Joint CCAs including Apple Valley Choice

[8] This waiver only applies to the RPS Procurement Plans filing requirement. All retail sellers must continue to file annual RPS compliance reports.

Energy, Monterey Bay Community Power Authority, Peninsula Clean Energy Authority, Pioneer Community Energy, Redwood Coast Energy Authority, Silicon Valley Clean Energy Authority, Sonoma Clean Power Authority, Valley Clean Energy Authority and East Bay Community Energy.

1.2. RPS Program Status

The three large IOUs report RPS progress in excess of program procurement requirements, which mandate a 25% RPS by 2017. For 2017, the IOUs delivered the following percentages of energy from RPS-eligible resources: PG&E 33%; SCE 32%; and SDG&E 44%.

None of the three large IOUs (PG&E, SCE, and SDG&E) conducted a 2017 annual RPS solicitation. All three large IOUs continued to procure through their feed-in tariff (market adjusting tariff (BioMAT)) and green tariff renewable auction mechanism (RAM) programs. PG&E also completed its RAM procurement, which resulted in a total of 1,604 MW of approved contracts for all IOUs. A total of 1,574 Megawatts (MW) was authorized for procurement through eight RAM auctions.[9]

2. Plan of this Decision

The RPS statute requires that retail sellers prepare an annual RPS procurement plan for Commission review (Pub. Util. Code § 399.13(a)). The Commission has reviewed and approved or accepted annual RPS procurement plans for over 10 years. As the RPS program has matured, parties' review of the

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[9] The differential in authorized versus the amount procured was due to SDG&E procuring approximately 40% of its target. D.10-12-048 at 31 and Ordering Paragraph (OP) 1 requires that any contracted capacity that is not successfully developed must be added back to that IOU's procurement obligation to be sourced at subsequent auctions. As a result, the amount approved by the Commission (1,532 MW) is higher than what is ultimately authorized (1,405 MW).

three large IOUs' procurement plans has become more routine. This year, 2018, marks the fourth year in a row that PG&E and SDG&E will forgo an annual RPS solicitation; it is the third year in a row for SCE.

In light of all the above, for ease of review, this year's decision accepting the RPS procurement plans is shorter than past years. It describes only the sections of the IOUs' procurement plans that are at issue, and those responses to the *2018 ACR* that are relevant to our decision to grant the IOUs' request to forego an RPS solicitation. This decision accepts the plans in their entirety, as modified herein, subject to approval of the required compliance filings.

3. General Requirements for 2018 Procurement Plans

The RPS procurement process continues to evolve since the beginning of the RPS program. The procurement plans include long-standing elements, such as standard terms and conditions that must be included in each RPS pro forma contract. Legislative changes to the RPS statute impact retail sellers' RPS procurement plans. This was the case with SB 350 (De León, 2015), which further extended the RPS program targets, including changes to RPS procurement rules such as changes that affect the role of long-term contracts in RPS procurement requirements and the methodology for determining how excess procurement in one compliance period may be applied to later compliance periods. SB 350 also clarified and expanded the RPS procurement plan reporting requirements for CCAs and ESPs. The Commission has implemented SB 350 in several Commission decisions, including D.16-12-040,[10] D.17-06-026,[11] D.18-05-026.[12]

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[10] *Decision Implementing Compliance Periods and Procurement Quality Requirements for Compliance with the Revised Requirements of the California Renewables Portfolio Standard Mandated By Senate Bill 350, December 15, 2016.*

These Commission decisions contain directives that required modifications to the RPS procurement process. The details of these decisions are not repeated here.

The latest update to the RPS program targets from SB 100 (De León, 2018), extends the Portfolio Quantity Requirement to 60% of retail sales of electricity products from eligible renewable energy sources by December 31, 2030.

The *2018 ACR* instructed that the proposed 2018 RPS Procurement Plans should reflect recent statutory changes. An e-mail Ruling was sent out on September 19, 2018 and ordered all IOUs, CCAs, and ESPs to serve updates to their Draft 2018 Renewable Portfolio Standard Procurement Plans to address SB 100.

Consistent with the Commission's decisions and applicable statutory changes, compliance with all of the requirements set forth in the *2018 ACR* is required by the three large IOUs. The *2018 ACR* also stated that small and multi-jurisdictional utilities are subject to a subset of the requirements the ACR identified. ESPs and CCAs are also subject to a subset of these requirements.

As indicated in the *2018 ACR*, the 2018 Procurement Plans must include all information required by statute, as well as quantitative analysis supporting the retail seller's Assessment of its RPS portfolio and future procurement decisions. The *2018 ACR* identified the following information for inclusion in the 2018 Procurements Plans:

- Assessment of RPS Portfolio Supplies and Demand (Section 5.1);
- Project Development Status Update (Section 5.2);

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[11] *Decision Revising Compliance Requirements for the California Renewables Portfolio Standard in Accordance with Senate Bill 350, June 29, 2017.*

[12] *Decision Implementing SB 350 Provisions on Penalties and Waivers for the Renewable Portfolio Standard Program May 31, 2018*.

- Potential Compliance Delays (Section 5.3);
- Risk Assessment (Section 5.4);
- Quantitative Information (Section 5.5);
- "Minimum Margin" of Procurement (5.6);
- Bid Solicitation Proposal, Including Least-Cost Best-Fit Methodologies (5.7);
- Consideration of Price Adjustment Mechanisms (5.8);
- Curtailment Frequency, Costs, and Forecasting (5.9);
- Cost Quantification (5.10);
- Important Changes to Plans Noted (5.11);
- Redlined Copy of Plans Required (5.12); and
- Safety Considerations (5.13).

The *2018 ACR* instructed the parties that all of the proposed 2018 RPS Procurement Plans must achieve the following:

1. Describe the overall plan for procuring RPS resources for the purposes of satisfying the RPS program requirements while minimizing cost and maximizing value to ratepayers. This includes, but is not limited to, any plans for building utility-owned resources, investing in renewable resources, and engaging in the sales of RPS eligible resources.
2. The various aspects of the plans themselves must be consistent. For instance, the bid solicitation protocol should be consistent with any statements and calculations regarding a utility's renewable net short position.[13]
3. The plans should be complete in describing and addressing procurement (and sales) of RPS eligible resources such that the Commission may accept or reject proposed contracts based on

[13] The methodology can be found at the May 21, 2014 ruling, *Administrative Law Judge's Ruling on Renewable Net Short*. (R.11-05-005).

consistency with the approved plan, including any calculation of RPS procurement net short position.[14]

IOUs should work collaboratively to make the format of the plans as uniform as possible to enable parties, bidders, and the Commission to easily access, review and compare the plans.

4. Utilities Subject to Pub. Util. Code § 399.17

RPS procurement requirements for multi-jurisdictional utilities and their successors allow these utilities to meet their RPS procurement obligations without regard to the portfolio content category limitations in Pub. Util. Code § 399.16.[15] Multi-jurisdictional utilities, *i.e.*, PacifiCorp, also have the ability to use an Integrated Resource Plan (IRP) prepared for regulatory agencies in other states to satisfy the annual RPS Procurement Plan requirement so long as the IRP complies with the requirements specified in Pub. Util. Code § 399.17(d). PacifiCorp prepares its IRP on a biennial schedule, filing its plan in odd numbered years. It files a supplement to this plan in even numbered years.

As required by D.08-05-029, PacifiCorp must file and serve its IRP in Rulemaking (R.) 06-05-027 or its successor proceeding at the same time it files with the jurisdictions requiring the IRP, and an IRP Supplement within 30 days of filing its IRP. PacifiCorp filed its 2018 "off year" supplement to its 2017 IRP on July 16, 2018 and an updated IRP supplement on October 8, 2018.

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[14] Pub. Util. Code § 399.13(d).

[15] Pub. Util. Code § 399.17(b).

5. Utilities Subject to § 399.18

Pub. Util. Code § 399.18(b) allows a small utility to meet the RPS procurement obligations without regard to the portfolio content category limitations in Pub. Util. Code § 399.16.

A small utility must file a procurement plan pursuant to Pub. Util. Code § 399.13(a)(5), but it should be tailored to the limited customer base and the limited resources of a small utility.

Accordingly, we required BVES, as well as Liberty to prepare an RPS Procurement Plan providing the information required in Sections 5.1-5.8 and 5.10-5.13 of the *2018 ACR.*

6. Electric Service Providers and Community Choice Aggregators

SB 350 revised the Commission's requirements regarding what entities it shall direct to file RPS Procurement Plans. ESPs and CCAs must now file RPS Procurement Plans consistent with the requirements of Pub. Util. Code § 399.13(a)(5). Therefore, we required each ESP and CCA to file a proposed RPS Procurement Plan that complies with the requirements of sections 5.1-5.6, 5.8, and 5.11-5.13 of the *2018 ACR*.

7. PG&E's RPS Procurement Plan

7.1. Summary of Key Issues and Important Recent Legislative and Regulatory Changes in the RPS Program[16]

Key Issues

First, PG&E states it does not have an incremental need 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 (Bank) toward its current-year RPS needs beginning in 2026.

But PG&E claims its RPS need is subject to uncertainty caused by the following factors:

1. If the Joint IOU's 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 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 Procurement Plan has been updated to incorporate the revised RPS requirements as set forth by SB 100,[17] which was signed by the Governor on September 10, 2018. Otherwise, this 2018 RPS Procurement Plan assumes the current RPS law remains unchanged and that the Commission

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16 PG&E's 2018 RPS Plan at 1-6 (originally filed on August 20, 2018, and updated on October 8, 2018).

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

> 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.

Second, PG&E is proposing not to hold an RPS procurement solicitation for the 2018 solicitation cycle. 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).[18]

Third, 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 long-term RPS sales in 2019. This will help to address the fact that PG&E's forecasted RPS position predicts a higher cumulative Bank than its calculated minimum Bank needed to ensure compliance in light of regular fluctuations in supply and demand.

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[18] Mandated programs include ReMAT and Bioenergy Market Adjusting Tariff (BioMAT). The ReMAT program is currently the subject of litigation in federal court and has been enjoined. In addition, while it will not directly impact PG&E's renewable net short (RNS), PG&E expects to procure additional volumes over the next year for the Green Tariff Shared Renewables (GTSR) Program.

Fourth, PG&E opposes mandates that result in what it claims are unnecessary and/or unreasonable costs for customers. Despite PG&E's absence of need for additional RPS resources, PG&E continued in 2018 to procure required RPS-eligible volumes through the legislatively-mandated BioMAT program and the solar photovoltaic Renewable Auction Mechanism (PV RAM) program.

Fifth, PG&E claims that its RPS procurement and sales strategies are dependent on the resolution of the PCIA reform proceeding. As of the date PG&E filed this amended 2018 RPS Procurement Plan, the Commission had not resolved the PCIA proceeding. But that changed on October 11, 2018, when the Commission adopted D.18-10-019, *Decision Modifying the Power Charge Indifference Adjustment Methodology*. D.18-10-019 rejected the IOUs' proposal for a Green Allocation Mechanism (GAM) that would allocate utility RPS resources to departing customers, including CCAs, thereby reducing the renewable energy credits (REC) that IOUs would hold to serve bundled customers and allocating those RECs to customers served by CCAs and ESPs:

> This Commission will not pursue a policy scheme of mandatory portfolio allocation to CCAs and ESPs to resolve the problem of excess resources in the Joint Utilities' portfolios. We decline to adopt the Joint Utilities' GAM or PMM proposals for the policy reasons indicated above.
>
> In phase two of this proceeding, we will explore voluntary, market-based solutions.[19]

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[19] D.18-10-019 at 96, and Conclusion of Law 6: "It is not necessary to require ESPs and CCAs to accept allocations of Resource Adequacy (RA) and RPS attributes in order to prevent cost shifting between bundled load customers and departing load customers."

Thus, we do not believe that it is necessary for PG&E to update any of its procurement and sales strategies in its final 2018 RPS Procurement Plan as a result of D.18-10-019.

PG&E's Summary of Important Recent Legislative and Regulatory Changes to the RPS Program[20]

PG&E claims its portfolio forecast and procurement decisions are influenced by legislative and regulatory changes related to the RPS Program. The quantitative analysis provided in this 2018 RPS Procurement Plan only considers statutes enacted as of September 19, 2018. Legislation enacted after September 19, 2018, that will likely impact PG&E's Renewable Net Short (RNS) in the future, depending on how these bills are implemented, includes SB 237,[21] which is expected to increase the participation cap for the State's Direct Access program by 4,000 Gigawatt hours (GWh) statewide, and SB 901,[22] which requires the IOUs to seek to extend the delivery terms of RPS-eligible biomass contracts that meet certain feedstock and other requirements. 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 Procurement Plan to pursue RPS sales and to not undertake a procurement solicitation in 2019.

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[20] PG&E's 2018 RPS Plan at 7-17.

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

[22] SB 901, Stats. 2018, Ch. 626 (Dodd).

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% by the end of 2024; 52% by the end of 2027; and 60% by 2030 and thereafter. PG&E's quantitative analysis in this 2018 RPS Procurement Plan, including its RNS tables, reflect these increased targets. Separately, SB 100 adopts a statewide policy that 100% of California's retail sales must come from RPS-eligible and zero-carbon resources by 2045.

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. 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.[23]

On December 15, 2016, the Commission adopted D.16-12-040, which implements the new compliance periods and Procurement Quantity Requirements (PQR)[24] 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

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[23] *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.

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

periods beginning January 1, 2021. 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. Accordingly, the analysis set forth in the 2018 RPS Procurement 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 Procurement 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.

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% reduction in Greenhouse Gas (GHG) emissions below 1990 levels by 2030, a 50% 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.[25] This 2018 RPS Procurement 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.[26] 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 and rooftop solar.

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[25] 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.

[26] 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.

Diablo Canyon Retirement Joint Proposal Application

On August 11, 2016, PG&E and the Joint Parties[27] filed an Application requesting Commission approval of the retirement of Diablo Canyon nuclear power plant. The Commission issued D.18-01-022 on January 16, 2018, approving PG&E's proposal to retire Diablo Canyon by 2025

7.2. Assessment of RPS Portfolio Supplies and Demand[28]

7.2.1. Supply

PG&E claims it delivered 33.0% of its electricity from RPS-eligible renewable sources in 2017. PG&E projects that it is positioned to meet its RPS compliance requirements through compliance period (CP 5) (2025-2027).

PG&E's RPS portfolio is comprised of a variety of technologies, project sizes, and contract types. The portfolio includes approximately 8,000 MWs of active projects, ranging from utility-owned solar and small hydro generation to long-term RPS contracts for large wind, geothermal, solar, and biomass to small FIT contracts for solar photovoltaic (PV), biogas, and biomass generation.

PG&E believes that the GTSR, enacted by SB 43, also has an impact on its supply analysis. In PG&E's estimation, the GTSR Program will impact its RPS position in two ways: RPS supply may be increased, and retail sales will be reduced corresponding to the level of program participation. D.15-01-051 permits the IOUs to supply Green Tariff (GT) customers from an interim pool of existing RPS resources until new dedicated GT projects come online. Generation

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[27] 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.

[28] PG&E's 2018 RPS Plan at 16-26.

from these interim facilities would no longer be counted toward PG&E's RPS targets, which will result in PG&E's RPS supply decreasing. However, there is also a possibility that RPS supply might increase in the future if generation from GT dedicated projects exceeds the demand of GT customers.

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

7.2.2. Demand

PG&E states its 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. The Commission will evaluate the need for modifications to incorporate the revised statutory RPS targets in the recently enacted SB 100.

Another variable is the advent of transportation electrification. PG&E claims its 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 transportation electricity demand forecast in developing its EV forecast.

Because PG&E claims it has no immediate incremental procurement need until after 2033 under existing RPS requirements, it is proposing not to hold an RPS solicitation for the solicitation cycle for the year 2019. PG&E believes that it 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 Procurement 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 based on its forecasted load.

7.2.3. Lessons Learned

As for lessons learned and market trends, PG&E notes that the renewable energy market has developed and now offers a variety of technologies at lower prices than seen in earlier RPS Program years. PG&E has also observed the growth of renewable resources in the CAISO system has resulted in the downward movement of mid-day wholesale energy market prices. PG&E has also observed that the growth of renewable resources has produced operational challenges such as over generation situations and negative market prices. PG&E asks for contract provisions that will provide it with greater flexibility to bid RPS-eligible resources into the CAISO market or exercise curtailment rights based on CAISO market prices. These provisions, in PG&E's estimation, 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.

7.3. Project Development Status Update[29]

PG&E, SCE, and SDG&E file monthly RPS Database submissions with the Commission. 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.

7.4. Potential Compliance Delays[30]

In general, PG&E states that it does not currently foresee obstacles to achieving compliance with existing RPS requirements. But market conditions and changes in law and regulatory requirements could change this outlook in the future. For example, 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.

Finally, PG&E states that it employs risk-adjusted analysis. It utilizes 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 of its 2018 RPS Procurement Plan, PG&E's expected RPS need calculation incorporates a minimum margin of

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[29] PG&E's 2018 RPS Plan at 31.

[30] *Id.*, at 32-34.

procurement to account for some anticipated project failure and delays in PG&E's existing portfolio.

7.5. Risk Assessment[31]

As with prior years' RPS procurement plans, PG&E states that it 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 which models three risks (standard generation variability, project failure, and project delay); and (2) a stochastic model which accounts for additional and uncertain variables (retail sales uncertainty, project failure variability, curtailment, and RPS generation variability). 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 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 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 *(i.e.* the banked volumes of excess procurement) 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.

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31 *Id.*, at 34-46.

7.6. Quantitive Information[32]

7.6.1. Deterministic Model Results

PG&E has provided the results from the deterministic model under a 60% by 2030 RPS target, and 60% RPS annually thereafter, 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 Long-Term Procurement Plan (LTPP) sales forecast for 2023-2036.[33] Appendix A.2 relies on PG&E's internal Bundled Retail Sales Forecast. PG&E currently estimates a long-term volumetric success rate of 100% for its portfolio of executed-but-not-operational projects. The annual forecast project failure rate used to determine the long-term volumetric success rate is shown in Row Fbb of Appendix A.2. In addition to the current long-term volumetric success rate, Rows Ga and Gb of Appendix A.2 depict PG&E's expected compliance position using the current expected need scenario before application of the Bank.

As noted above, PG&E believes it is positioned to meet its compliance period requirements through the fifth compliance period (2025-2027).

7.6.2. Stochastic Model Results

Because PG&E uses its stochastic model and internal Bundled Retail Sales Forecast to inform its RPS procurement, PG&E states it has created an Alternate RNS in Appendix A.2 to its 2018 RPS Procurement Plan for the 60% RPS target. Yet, PG&E claims that Appendix A.1 to its 2018 RPS Procurement Plan 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

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[32] *Id.*, at 47.

[33] *Id.*, at Appx. C.1, C.2.

to capture its stochastic modeling inputs and outputs. Rows Gd and Ge show the stochastically-adjusted net short, which incorporates the risks and uncertainties addressed in the stochastic model.

7.7. Margin of Procurement[34]

PG&E claims to consider two components when analyzing its margin of procurement: (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. PG&E incorporates both of these components into its quantitative analysis of its RPS need.

7.8. Bid Selection Protocol[35]

Because it believes it is positioned to meet its RPS targets until after 2033, PG&E proposes not to hold a 2019 procurement solicitation. PG&E will continue to procure RPS-eligible resources in 2019 through other Commission-mandated programs, such as the BioMAT program. Accordingly, PG&E has not included in the 2018 RPS Procurement 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 Net Market Value and Portfolio Adjusted Value (PAV) methodologies, included in PG&E's final 2014 RPS RFO Protocol

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[34] *Id.*, at 54-56.

[35] *Id.*, at 56-58.

(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 Procurement 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.

7.8.1. Proposed Time of Delivery Factors

PG&E sets its 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 Procurement 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 Procurement 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, PG&E believes that TOD factors in a long-term PPA are unlikely to reflect system need over the entire life of the PPA. In fact, PG&E believes that 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, PG&E notes that inserting contractual provisions that allow PG&E to alter TOD factors on a regular basis to match system 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. (A further discussion of TOD factors is provided, *infra*, at Section 11.4 of this proposed decision.)

7.8.2. Workforce Development[36]

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." The 2018 RPS Procurement 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.

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[36] *Id.*, at 59.

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 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.

7.8.3. Disadvantaged Communities[37]

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." The 2018 RPS Procurement Plan Ruling directs the IOUs to include a description of their methodology for preferring projects that provide those benefits.

As explained above, PG&E states that it 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

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[37] *Id.*, at 60.

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. 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:
>
> - 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?

7.9. Consideration of Price Adjustment Mechanisms

The 2018 RPS Procurement Plan Ruling requires each IOU to "describe how price adjustments (e.g., index to key components, index to Consumer Price

Index, 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."

In this 2018 RPS Procurement 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 believes that 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. In order to maximize the RPS Program's benefits to customers, cost risk should generally be borne by developers.

7.10. Economic Curtailment

In D.14-11-042, the Commission directed that the IOUs describe in future RPS Procurement Plans how "expected economic curtailment affects their RPS procurement." In addition, the Commission directed the IOUs to report on observations and issues related to economic curtailment, including reporting to the Procurement Review Group (PRG). 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, PG&E asserts that the frequency of negative price periods in the first part of 2018 has decreased in the Real-Time Markets 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 price intervals in the CAISO Five Minute Market for the PG&E DLAP occurred in approximately 4.2% of the 5-minute intervals, compared to approximately 13.5% during the same period in 2017 and 7.6% during the same period in 2016. Trends are similar for NP 15 and ZP 26.

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. PG&E will continue to observe curtailment events and update its curtailment assumptions as needed.

Finally, PG&E claims to continue reviewing its existing portfolio of RPS contracts to determine if additional economic curtailment flexibility may be available to help reduce oversupply events.

7.11. Cost Quantification[38]

Tables 1 through 4 in Appendix B to its 2018 RPS Procurement Plan 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. Appendix B quantifies the cost of RPS-eligible procurement—both historical (2003-2017) and forecast (2018-2030). From 2003 to 2017, PG&E's

[38] *Id.*, at 66-69.

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.

7.12. Important Changes to Plans Noted[39]

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

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,	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	LCBF Methodology	Updates to reflect current market conditions

39 PG&E's 2018 RPS Plan at 69.

7.13. Safety Considerations[40]

PG&E claims that its 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). Thus, it discusses safety considerations from those two separate perspectives.

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

PG&E claims to operate 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 (GO) 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.

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

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40 *Id.*, at 69-70.

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 claims it 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.

PG&E claims that, over the past several years, its 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.

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

PG&E claims that the 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 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.

PG&E also claims that safety is 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.

7.14. Energy Storage[41]

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

[41] *Id.* at 74-75.

2016 Energy Storage RFOs. In D.18-10-009, the CPUC approved six executed agreements that PG&E executed as a result of the 2016 Energy Storage RFO.

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, and selected for approval four projects located within the South Bay – Moss Landing local sub-area: one for a 182.5 MW utility-owned project, and three for 385 MW of third-party owned projects, which include a 10 MW aggregation of customer-sited storage. Energy storage procured to meet the local sub area need will be used to meet PG&E's AB 2514 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 Pub. Util. Code §§ 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.

PG&E states that it 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.

7.15. Cost Containment

In meeting its RPS requirements, PG&E claims it 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. PG&E supports establishment of a PEL pursuant to SB 2 (1X 2011) in order to protect customers from excessive costs.

8. SCE 2018 RPS Procurement Plan

8.1. Summary[42]

In its 2018 RPS Procurement Plan, SCE proposes to not hold a 2018 RPS solicitation for the procurement of eligible renewable resources. If SCE's preferred scenario as set forth in the IRP proceeding[43] is adopted, then SCE may seek to hold a solicitation to procure non-GHG emitting resources, including renewable energy in excess of the RPS requirements. In this RPS docket, SCE proposes to sell RECs, as described in Section XI of its Plan and in Appendix E attached thereto.

If in future years SCE holds a solicitation, SCE proposes to use a solicitation process that is intended to capitalize on the maturing renewables

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[42] SCE's 2018 RPS Plan, August 20, 2018, updated October 8, 2018, at 1-6.

[43] R.16-02-007.

market and target the most viable proposals that fit SCE's compliance and reliability needs and provide the most value to customers. In order to submit a proposal, SCE will require that projects have: (1) a Phase II Interconnection Study (or an equivalent or more advanced interconnection status or exemption); and (2) an "application deemed complete" (or equivalent) status within the applicable land use entitlement process. Because of uncertainty surrounding SCE's long-term load forecast due to potential changes in its load profile (*i.e.*, the effects of electric transportation, local solar PV generation, and departing load), SCE would request that all bidders submit one offer for a term of 10 years or less for each project.

In this 2018 RPS Procurement Plan, SCE states that it will request offers from parties interested in purchasing REC products from SCE. In its 2017 RPS Plan, SCE planned to request offers from parties interested in purchasing Category 1 REC products only. In this 2018 RPS Procurement Plan, SCE expands its proposal for the REC products that it may sell in order to maximize its flexibility to sell a variety of REC products. Also, SCE may bid into other parties' solicitations seeking REC products. Assuming the adoption of the IOUs' GAM proposal in the PCIA OIR, SCE forecasts a net short position after 2027 with the use of bank. The CPUC rejected this proposal in October 2018 in D.18-10-019. Assuming that no REC allocation methodology is adopted in the PCIA proceeding, SCE does not forecast a net short position potential through 2030 and beyond with the use of bank. Additional uncertainty exists regarding other factors such as the future departing load levels, especially as it relates to the formation of additional CCAs (*see* Section II.F.1.A in its 2018 RPS Procurement Plan for a discussion on CCAs). Therefore, in order to maximize value for customers, SCE may sell REC products, consistent with its proposal in this 2018 RPS Procurement Plan.

8.2. Assessment of RPS Portfolio Supplies and Demand[44]

8.2.1. Renewables Portfolio

Table II-1 below shows SCE's percentage of retail sales for its RPS-eligible resources:

Table 8-1

Percentage of SCE's Retail Sales from RPS-Eligible Resources

Compliance Period	Year(s)	% of Retail Sales from RPS Eligible Resources
First	2011-2013	20.6
Second	2014-2016	25.3
2017	2017	31.6

To date, SCE's RPS-eligible deliveries and executed renewable procurement contracts have resulted from SCE's RPS solicitations, SCE's Renewables Standard Contract program, the AB 1969 feed-in tariffs, RAM and Bioenergy Renewable Auction Mechanism auctions, ReMAT, BioMAT, the utility-owned generation and independent power producer portions of SCE's Solar Photovoltaic Program, the GTSR program, QF contracts, utility-owned small hydro projects, and bilateral opportunities.

SCE did not hold an RPS Solicitation in either 2016 or 2017. However, in 2017 and so far in 2018, SCE has signed the following renewable contracts:

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44 SCE's 2018 RPS Plan at 7-26.

- Three ReMAT contracts for 7.5 MW
- Two QF standard offer contracts for approximately 0.6 MW; and
- Five BioMAT contracts for approximately 8.2 MW.

8.2.2. Renewable Procurement Need

SCE states that it determines its expected renewable procurement need by comparing its forecasted RPS targets to its forecasted energy deliveries from contracted projects. The forecasted energy deliveries include SCE's probabilistic risk-adjusted forecast of generation from contracted projects that are not yet online. SCE also considers generation from pre-approved procurement programs (*i.e.*, ReMAT, BioMAT), among other factors.

Appendices C.1 through C.8 of SCE's 2018 Plan include SCE's forecast of its renewable procurement position and need – i.e., SCE's RNS – based on the RPS targets adopted by the Commission in D.11-12-020 for all years through 2020 as well as the new RPS goals prescribed in SB 100 for the years 2021 through 2030. In anticipation of CPUC implementation of compliance during intervening years, SCE has used the same "straight line" method set out in D.11-12-020 to determine interim year targets and procurement requirements.

SCE's load forecast also accounts for future Transportation Electrification (TE) load growth.[45] SCE developed its own internal model to forecast EV adoption and considers TE load as a positive load contributor.

As a nascent and dynamic market, EV adoption is affected by multiple drivers such as manufacturer supply, policies set by federal, state, and local governments, and EV technology advancement. SCE models light-duty EV

[45] TE refers to only light-duty electric vehicles here.

through a Generalized Bass Diffusion model. Once vehicle population numbers are determined for each year, SCE calculates the total annual load by multiplying the number of forecasted EVs by the weighted average KWh usage per vehicle. Multiple factors are considered to determine hourly, daily, and annual EV charging load shapes. SCE then incorporates the EV load forecast into its demand forecast used in this 2018 RPS Procurement Plan.

Assuming adoption of GAM with SCE's assumptions, SCE forecasts a net short position starting in 2023 without the use of bank (as shown in Appendix C.2). But with the use of bank, SCE forecasts a net long position through the end of CP 4 (2021-2024) (as shown in Appendix C.4). Using the Commission's assumptions, SCE forecasts a net short position starting in 2023 without the use of bank (as shown in Appendix C.1) and a net long position through the end of CP 4 (2021-2024) with the use of bank (as shown in Appendix C.3). Accordingly, SCE currently does not have a near-term need for additional RPS-eligible energy assuming adoption of GAM.[46] The CPUC rejected the GAM proposal in October 2018 in D.18-10-019.

Using either Commission or SCE assumptions, SCE's net short position may be impacted if some form of bank restrictions are adopted in the future.

Assuming adoption of no allocation of RECs in the PCIA with SCE's assumptions, SCE forecasts a net short position starting in 2027 without the use

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[46] This conclusion assumes incremental departing load from CCA development based on SCE's 2018 Q2 assumptions. Operational and expected CCAs as well as a Monte Carlo simulation of additional CCA load beginning in 2020 are currently accounted for in SCE assumptions for departing load. SCE performs scenario analysis for departing load when making procurement decisions based on the best information available at that time. SCE shares this information with its Procurement Review Group (PRG) including Energy Division. *See* section II.F, subsection 1, at 22-24, for a detailed explanation of SCE's CCA outlook.

of bank (as shown in Appendix C.6). But with the use of bank, SCE forecasts a net long position through the end of CP 6 (2028-2030) and beyond (as shown in Appendix C.8). Using the Commission's assumptions, SCE forecasts a net short position starting in 2026 without the use of bank (as shown in Appendix C.5) and a net long position through the end of CP 6 (2028-2030) and beyond with the use of bank (as shown in Appendix C.7). Accordingly, SCE currently does not have a need for additional RPS-eligible energy assuming adoption of no allocation of RECs in PCIA.[47]

8.2.3. Lessons Learned[48]

SCE claims to refine both its RPS solicitation process and its pro forma PPA as a result of lessons learned from SCE's extensive experience in contracting for renewable resources and working with developers. Over the course of the last several years, SCE has also incorporated or accounted for several trends in its renewable procurement planning and solicitation process.

SCE states that it expects additional cities and eligible public entities within the SCE service territory to begin CCA service. SCE had its first departing

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[47] SCE states that this conclusion assumes incremental departing load from CCA development based on SCE's 2018 Q2 assumptions. Operational and expected CCAs as well as a Monte Carlo simulation of additional CCA load beginning in 2020 are currently accounted for in SCE assumptions for departing load. *See* section II.F, subsection 1 at 22-24 in SCE's 2018 RPS Plan for an explanation of SCE's CCA outlook. SCE performs scenario analysis for departing load when making procurement decisions based on the best information available at that time. SCE shares this information with its PRG including Energy Division.

[48] SCE states that this conclusion assumes incremental departing load from CCA development based on SCE's 2018 Q2 assumptions. Operational and expected CCAs as well as a Monte Carlo simulation of additional CCA load beginning in 2020 are currently accounted for in SCE assumptions for departing load. *See* section II.F, subsection 1 at 22-24 in SCE's 2018 RPS Plan for an explanation of SCE's CCA outlook. SCE performs scenario analysis for departing load when making procurement decisions based on the best information available at that time. SCE shares this information with its PRG including Energy Division.

CCA load starting in May 2015 in the form of Lancaster Choice Energy. Apple Valley Choice Energy began operations at the beginning of April 2017, followed by Pico Rivera Innovative Municipal Energy in October 2017, Clean Power Alliance (CPA or Los Angeles County) Phase I implementation in February 2018, San Jacinto Power in April 2018, Rancho Mirage Energy Authority in May 2018, and CPA Phase 2 in June 2018. Desert Communities Energy (DCE) was expected to begin service in August 2018[49] followed by three additional phases of CPA covering much of Los Angeles and Ventura counties in 2019. Additional cities, counties, and governmental aggregations within the SCE service territory have either initiated contact, requested load data from SCE, or passed a municipal ordinance related to their interest and intention to developing CCAs. These entities have the potential to represent a significant departure of load from SCE's bundled procurement service. As additional large departures come to fruition, they will have proportionally significant impacts on SCE's compliance with RPS goals by reducing SCE's RPS need.

SCE asserts that departing load should not impact its planned procurement activities unless and until new LSEs formalize their departure through a Binding Notice of Intent (BNI), an initial Resource Adequacy (RA)

[49] At a July 25, 2018 DCE Board Meeting, DCE voted to indefinitely delay their previously-planned August 2018 implementation date. Their new implementation date (if any) is not currently known. SCE will not know about DCE's final decision on all of the implementation plan changes -- especially for 2019 -- in time for us to make appropriate changes to our load forecast for this filing. It should be noted, however, that DCE's forecast peak load was only 385 MW in 2018, and DCE's delay in pursuing CCA implementation does not materially affect the overall point that SCE is significantly long regarding RPS targets for the foreseeable future.

filing, the start of CCA service, or formal submission of an April RA forecast for the following year pursuant to California Public Utilities Code Section 380.[50]

SCE believes it is well positioned to meet its RPS compliance obligation both in the near term and in the future. As described in confidential Appendix E, SCE has more renewable energy to meet its compliance responsibilities than it needs for the forseeable future. Additionally, SCE can create customer value and introduce some rate stability by engaging in sales transactions. The Commission adopted SCE's REC sales strategy in its Draft 2017 RPS Plan, with some minor modifications, in D.17-12-007.[51]

In addition to providing benefits to SCE's customers, SCE believes that an open market for REC sales may provide for a low cost option for RPS compliance for other LSEs in California.[52]

Finally, given the SB 350 changes in compliance rules confirmed in D.17-06-026, IOUs will have some flexibility to fulfill their compliance requirements through a combination of long term contracts and short-term products, reducing the overall costs for their customers. Given this change, SCE states it will seek portfolio optimization opportunities to make those tradeoffs between long-term contracts and short-term purchases. An active REC sales strategy will be a key part of SCE's portfolio optimization strategy.

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[50] SCE's internal criteria for a qualifying governmental entity to be included in the CCA departing load forecast with full certainty for bundled procurement forecast purposes.

[51] D.17-12-007, OP 8 at 71-72.

[52] As explained in more detail in section XI and confidential Appendix E of SCE's 2018 RPS Plan.

8.3. Project Development Status Update[53]

Appendix B to SCE's 2018 RPS Procurement Plan contains a status update on the development of RPS-eligible projects currently under contract, but not yet delivering generation.

8.4. Potential Compliance Delays[54]

SCE identifies six factors that may challenge its achievement of the RPS goals: (1) curtailment; (2) the increasing proportion of intermittent resources in SCE's renewables portfolio; (3) permitting, siting, approval, and construction of both renewable generation projects and transmission; (4) a heavily subscribed interconnection queue; (5) developer performance issues; and (6) load uncertainty associated with possible departing load and increasing electrification of transportation. Each one of these factors is discussed in its 2018 RPS Procurement Plan.[55]

8.5. Risk Assessment[56]

SCE states that it accounts for potential issues that could delay RPS compliance, project development status, minimum margin of procurement, and other potential risks through the use of probabilistic risk-adjusted success rates for energy deliveries from contracts that are executed but not yet online. SCE considers these risk factors in this process. Additionally, SCE says it takes into account historic generation from existing resources, including lower than expected generation, variable generation, and resource availability, among other

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[53] SCE's 2018 RPS Plan at 26.

[54] *Id.*, at 26-30

[55] *Id.*

[56] *Id.*, at 31.

factors, when forecasting expected generation from its contracted renewable projects. The quantitative analysis provided in Appendices C.1 through C.8 of SCE's 2018 RPS Procurement Plan reflects these considerations.

8.6. Quantitative Information[57]

According to SCE, Appendices C.1 through C.8 of SCE's 2018 RPS Procurement Plan include SCE's RNS calculations using the standardized reporting template included in the RNS Ruling under the RPS program rules. As required by the Commission's RNS Methodology, Appendices C.1, C.2, C.5, and C.6 of SCE's 2018 RPS Procurement Plan include physical RNS calculations, and Appendices C.3, C.4, C.7, and C.8 of SCE's 2018 RPS Procurement Plan include optimized RNS calculations.

Appendices C.2, C.4, C.6, and C.8 of SCE's 2018 RPS Procurement Plan include SCE's physical RNS and optimized RNS through 2030, based on the following SCE assumptions:[58]

- SCE's most recent bundled retail sales forecast for 2018 through 2030 which excludes Green Rate customer subscriptions;
- Transfers of energy deliveries from SCE's interim pool of RPS eligible resources to the Green Rate program to serve Green Rate customers until dedicated Green Rate resources come online; and conversely, transfers of energy deliveries from dedicated Green Rate resource that are not used by Green Rate customers;
- Contracted projects that are currently online will deliver 100% of their expected amount of renewable energy;

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57 *Id.*, at 32-38.

58 The physical RNS shows SCE's RPS position without the use of its bank, and the optimized RNS shows SCE's RPS position with the use of its bank.

- Probabilistic risk-adjusted success rates for energy deliveries from contracted projects that are not yet online. SCE's forecasts include individual project-specific, risk-adjusted success rates for large, near-term projects and a flat 70% success rate for the remaining projects, which is based on these projects' overall weighted average success rate; and
- 100% success rate for projects originating from pre-approved programs such as ReMAT and BioMAT before contracts from such programs are signed.

Appendices C.1, C.3, C.5, and C.7 of SCE's 2018 RPS Procurement Plan provide SCE's physical and optimized RNS through 2030 using the Commission's RNS Methodology. Appendices C.1, C.3, C.5, and C.7 of SCE's 2018 RPS Procurement Plan use the same assumptions as in Appendices C.2, C.4, C.6, and C.8 except that: Instead of using SCE's most recent bundled retail sales forecast for all years, they use SCE's most recent bundled retail sales forecast for 2017 through 2022 and the annual load forecasts through 2030 reflected in the 2017 Integrated Energy Policy Report with adjustments for updates to certain CCA load Forecasts.[59]

8.7. Minimum Margin of Procurement[60]

SCE states that its renewable procurement efforts will be guided by its forecast of its renewable procurement needs, as provided in Appendices C.1 through C.4 to its 2018 RPS Procurement Plan.

In its forecast of its renewable procurement position and need, SCE currently accounts for the risks of project failure and delay associated with

[59] The Revised RNS Methodology states that retail sellers can use their own forecasts for bundled retail sales for the first five years and should use the LTPP standardized planning assumptions thereafter. *See* RNS Ruling, Attachment A at 25.

[60] SCE's 2018 RPS Plan at 39.

contracted projects that are not yet online. To this end, SCE uses individual project-specific, risk-adjusted success rates for large, near-term projects and a flat 70% success rate for the remaining projects, which is based on these projects' overall weighted average success rate.

SCE asks that the Commission rely on retail sellers to calculate their minimum margins of procurement and should not attempt to impose a one-size-fits-all approach. As many of the projects in SCE's portfolio become operational, SCE believes that it will face different risks, including integration of these resources. The risks associated with project failure will be replaced by less significant risks of projects generating below full capacity. Similarly, SCE expects that the portfolio risk picture is not the same for each retail seller. For example, risks may vary depending on whether a portfolio contains a high proportion of contracts that are online or depending on the various technologies being used (*e.g.*, geothermal technology, which is a baseload resource, versus wind or solar technologies, which are more intermittent). For these reasons, SCE suggests that each retail seller should continue to have the authority to revise its approach to calculating the minimum margin of procurement through the RPS procurement planning process and each retail seller should have the flexibility to calculate this margin based on its unique portfolio make-up and procurement needs.

8.8. Bid Solicitation Protocol, Including LCBF Methodologies[61]

8.8.1. Bid Solicitation Protocol

Depending on the outcome of the PCIA OIR proceeding SCE may hold a 2018 RPS solicitation, for sales of RECs. SCE states it will use the proposed 2018 Procurement Protocol, included as Appendix H.1 to SCE's 2018 RPS Procurement Plan, for these sales and for future RPS solicitations beyond 2018. The Procurement Protocol includes, among other things, the following items, some of which are not relevant for SCE's contemplated REC sales solicitation but are relevant for purchase solicitations in future years:

- SCE's requirements for initial delivery dates and preferred contract term lengths;
- Deliverability characteristics and locational preferences;
- SCE's preference for LCR projects;
- Encouragement for Women-Owned, Minority-Owned, Disabled Veteran-Owned, Lesbian-Owned, Gay-Owned, Bisexual-Owned, and/or Transgender-Owned Business Enterprises (Diverse Business Enterprises) to participate in SCE's RPS solicitation and information on how sellers can help SCE to achieve GO 156 goals;
- Requirements for each proposal submission;
- A description of the type of products SCE is soliciting;
- A schedule of key dates related to the RPS solicitation; and
- SCE's 2018 *Pro Forma* Renewable Power Purchase Agreement (Pro Forma), attached as Appendix F.1; and
- 2018 REC Sales Confirmation (2018 REC Sales Agreement).

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[61] *Id.*, at 40-41.

8.8.2. LCBF Methodology

In its LCBF evaluation process, SCE states that it performs a quantitative assessment of each proposal and subsequently ranks them based on each proposal's benefit and cost relationship. The result of the quantitative analysis is a rank order of all complete and conforming proposals' net levelized benefit that help define the preliminary shortlist. Following the quantitative analysis, SCE will conduct an assessment of the top proposals' qualitative attributes. These qualitative attributes, including factors such as local reliability, resource diversity, and nominal contract payments, are considered to either eliminate or add projects to the final shortlist or to determine tie-breakers, if any. Once a project is added to the shortlist, SCE may enter into a PPA with the project. By taking many quantitative and qualitative factors into consideration, SCE ensures that it will select projects best suited for its portfolio in order to meet customer needs and attain the State's RPS goals. Appendix G.1 (the LCBF Methodology) of SCE's 2018 RPS Procurement Plan describes this process, including capacity valuation and the renewable integration cost adder, among other factors.

There is one element of the current LCBF Methodology about which SCE states that it raised concerns in its Opening Comments on LCBF Reform, dated July 22, 2016--the use of TOD factors for evaluation and payment purposes. As discussed in more detail in Appendix G.1 of SCE's 2018 RPS Procurement Plan, SCE claims that TOD factors are unlikely to serve as an incentive for production of power when it is most needed in the future as solar and wind renewable resources have limited flexibility in their time of power production. While SCE states it does not eliminate the use of TOD factors in its LCBF valuation in this Written Plan, it will continue to argue for their elimination in future consideration of LCBF Reform. (TOD factors are discussed, *infra*, at Section 11.4 of this proposed decision.)

SCE also considers as qualitative factors in its LCBF valuation, the impact of a project on: (1) employment or Workforce Development; and (2) disadvantaged communities (DAC), which are identified through California's Environmental Protection Agency's CalEnviroScreen 3.0.

As stated previously in this written plan, IOUs will have some flexibility to fulfill their compliance requirements through a combination of long term contracts and short-term products, reducing the overall costs for their customers. Given this change, SCE will seek portfolio optimization opportunities to make those tradeoffs between long-term contracts and short-term purchases. An active REC sales strategy will be a key part of SCE's portfolio optimization strategy.

8.9. Consideration of Price Adjustment Mechanisms[62]

As in the past three RPS solicitations that SCE has held, SCE does not plan to solicit price structures based on indices in future RPS solicitations. Sellers can, however, bid escalation factors in their prices. Proposals with adjustable pricing based on indices were more common when the renewable industry was starting out. Uncertainties over relatively new technologies made it reasonable to tie pricing to certain commodity indices, inflation rates, or other indices that made sense given the technology. However, the industry is more sophisticated now, supply chains are becoming more stable, and price adjustment mechanisms based on indices are not needed. Sellers and SCE want price certainty, and SCE does not want to be subjected to what it deems extraordinary high (or

62 SCE's 2018 RPS Plan at 42-43.

unsustainably low) pricing due to fluctuations in a commodity or other indices. Additionally, the ability to bid price adjustments based on indices increases complexity for sellers in the proposal process and for SCE in the evaluation process. Developers are not requesting price adjustment mechanisms and the contract price risk uncertainty associated with them does not warrant their consideration.

8.10. Economic Curtailment, Frequency, Costs, and Forecasting[63]

SCE plans to bid resources with economic curtailment rights into the day-ahead and real-time markets. Resources with these curtailment rights will then be curtailed as needed based on CAISO's economic dispatch. In some SCE PPAs, there is a pre-defined amount of pre-paid energy per year that may be economically curtailed, subject to some restrictions, without requiring SCE to pay for the energy that could have been delivered but for the curtailment instruction. This amount is commonly referred to as a "curtailment cap." Once the curtailment cap is reached, SCE must pay the contract price for energy that could have been delivered but for the curtailment instruction. In other SCE PPAs, SCE claims it has the right to curtail based on economic factors but must always pay the contract price for energy that could have been delivered but for the curtailment instruction. These types of curtailment rights are commonly referred to as "take-or-pay." In instances where SCE has either exceeded the curtailment cap or only has "take-or-pay" economic curtailment rights to begin with, if SCE were not to curtail deliveries in excess of any schedules awarded at positive prices, customers would pay the contract price for that excess delivered

[63] SCE's 2018 RPS Plan at 43-44.

energy and incur the costs associated with negative pricing in such intervals. SCE's economic bids will therefore serve to further limit customer exposure to negative prices both day-ahead and in real-time, even if SCE ultimately pays the contract price for curtailed energy.

In future RPS solicitations, SCE states that it plans to not require sellers to bid the pre-paid economic curtailment option with the curtailment cap. SCE states that in future contracts it will retain the right to curtail at its discretion but will pay for curtailments directly resulting from SCE marketing decisions. As in prior years, future contracts will provide that SCE will not pay for curtailments in response to an emergency, or due to CAISO or transmission provider instructions.

8.11. Authorization to Sell Renewable Energy Credits[64]

SCE requests authorization to enter into a limited quantity of short-term renewable energy transactions for REC products through a Tier 1 Advice Letter Approval Process. SCE proposes and details one REC sales strategy assuming two different outcomes to the PCIA proceeding within Appendix E to SCE's 2018 RPS Procurement Plan . SCE believes it is well positioned to meet the CP 3 2020 33% RPS target with existing projects and projects under development (risk-adjusted). Therefore, SCE did not hold an RPS procurement solicitation for the 2016 and 2017 cycles. Also, if the Commission adopted the GAM proposal in the PCIA OIR proceeding, SCE forecast that it would have excess RECs at least through 2023 without the use of its REC bank and through CP 4 (2021-2024) with the use of the REC bank for compliance purposes. The Commission rejected the

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[64] *Id.*, at 45-53.

GAM proposal in October 2018 in D.18-10-0019. Assuming the Commission does not adopt a REC allocation methodology in the PCIA OIR proceeding, SCE forecasts that it will have excess RECs at least through 2027 without the use of its REC bank and through CP 6 (2028-2030) and beyond with the use of the REC bank for compliance purposes.

SCE proposes a Tier 1 Advice Letter Approach for approval of REC sales. SCE's proposed approach includes terms, volume limits, and a pricing floor as part of the preferred approach for the REC sales framework. Consistent with D.17-12-007, OP 8,[65] SCE will submit a Tier 1 Advice Letter filing for each of its REC sales from solicitations resulting from this 2018 RPS Procurement Plan or for bilaterally negotiated REC sales using the pro forma REC Sales Agreement attached t as Appendices I.1-I.5 to SCE's 2018 RPS Procurement Plan and executed after SCE receives bids for a sales solicitation resulting from this Written Plan. For REC Sales PPAs resulting from solicitations, a Tier 1 Advice Letter will include all REC Sales PPAs submitted as a group for the results of each concurrent solicitation (consistent with D.14-11-042). For bilaterally negotiated REC Sales PPAs using the pro forma REC Sales Agreement in Appendices I.1-I.5 to SCE's 2018 RPS Procurement Plan and executed after SCE receives bids for a sales solicitation resulting from this 2018 RPS Procurement Plan, a separate Tier 1 Advice Letter will include each bilaterally negotiated REC Sales PPA.

Consistent with D.17-12-007, SCE states that it may also engage in bilateral REC sales transactions that do not utilize the pro forma REC Sales Agreement

[65] D.17-12-007 at 71-72.

attached as Appendices I.1-I.5 to SCE's 2018 RPS Procurement Plan or that are not executed after SCE received bids for a sales solicitation resulting from its 2018 RPS Procurement Plan.[66] These bilateral REC sales transactions are subject to the Commission's review and approval of completed transactions through a Tier 3 Advice Letter process.[67]

SCE also asks permission to update its plan based on the outcome in the PCIA OIR proceeding. SCE expects to hold a net long REC position with any of the current alternate proposals and would likely still propose to sell RECs using the rationale and methods proposed above. However, SCE requests an opportunity to update this 2018 RPS Procurement Plan with modifications to its REC sales approach 60 days from the issuance of a final decision in R.17-06-026, if the Commission chooses an approach different from using the current PCIA methodology or the Joint Utilities' proposals. As noted above, the Commission did not adopt the Joint IOUs GAM or Portfolio Allocation Methodology (PAM) proposals. Thus, it is reasonable for SCE to update its sales strategies, if necessary, to reflect increases in RPS position forecasts that do not include GAM or PAM, in its final 2018 RPS Procurement Plan as a result of D.18-10-019.

8.12. Cost Quantification[68]

The spreadsheet attached as Appendix D to SCE's 2018 RPS Procurement Plan includes actual expenditures per year for RPS-eligible generation for every year from 2003 through 2017, as well as actual RPS-eligible generation for every year from 2003 through 2017. Appendix D also includes a forecast of future

[66] *See*, D.17-12-007 at 71-72, OP 8.

[67] *Id.*

[68] SCE's 2018 RPS Procurement Plan at 54.

expenditures SCE may incur every year from 2018 through 2030, as well as a forecast of expected generation for every year from 2018 through 2030.

8.13. Important Changes from 2017 RPS Procurement Plan[69]

SCE's 2018 RPS Procurement Plan includes changes to: (1) SCE's 2017 Procurement Protocol; (2) SCE's 2017 Pro Forma; (3) SCE's Pro Forma REC Sales Confirmation; and (4) SCE's LCBF Methodology. Those changes are summarized below. SCE has included redlines of its Procurement Protocol, Pro Forma, and LCBF Methodology against the 2017 versions of those documents included in SCE's 2017 RPS Plan as Appendices H.2, F.2, and G.2 to SCE's 2018 RPS Procurement Plan, respectively. SCE has also included a redline of its 2018 *Pro Forma* REC Sales Confirmation against the version of the document that was in its August 20, 2018 Draft 2018 RPS Procurement Plan in Appendix I.1A. SCE has made relatively few changes to these documents from the 2017 and 2018 documents. The most significant changes to the other 2017 and 2018 documents are summarized below.

8.13.1. 2018 Pro Forma

A redline of the 2018 *Pro Forma* showing all of the changes from the 2017 RPS *Pro Forma* is attached to SCE's 2018 RPS Plan as Appendix F.2. Important changes include:

1. Added that either party may terminate in the event of a Force Majeure prior to the Commercial Operation Date that extends beyond the Commercial Operation Deadline. Also, made clear that Force Majeure does not include a curtailment at the direction of the Transmission Provider or the CAISO when the curtailment

[69] *Id.*, at 55-58.

is caused by outages or capacity reductions due to maintenance construction or repair.

2. Added Seller indemnity obligations for: (i) violation of Applicable Laws or CAISO Tariff; (ii) release of hazardous material; and (iii) monetary penalties or fines against SCE by the CPUC resulting from Sellers willful or negligent failure to provide SCE with the full amount of RA.
3. Made changes related to late payment interest calculations including changing the calculation of "Interest Rate" to incorporate the average annual interest rates reported for all weekdays in the H.15 release published by the Federal Reserve.
4. Changed the Time of Delivery Periods and the Payment Allocation factors.
5. Modified language within certain sections of the agreement in order to address conformity within SCE contracting language across all solicitations
6. Other non-substantive changes made to the 2018 *Pro Forma* reflect a re-organization of certain credit terms and conditions in order to consolidate all of the credit related provisions into a single article within the 2018 *Pro Forma*.

SCE states that it changed the 2018 *Pro Forma* REC Sales Confirmation to broaden the potential market for its REC sales starting after approval of the 2018 RPS Plan. In particular, SCE includes in its 2018 RPS Plan a revised *Pro Forma* REC Sales Confirmation that will allow the parties to transact under either the International Swaps and Derivatives Association (ISDA) Master Agreement and associated Power Annex[70] or the Edison Electric Institute (EEI) Master Agreement. The *Pro Forma* REC Sales Confirmation in the 2017 RPS Plan and in the original Draft 2018 RPS Plan is consistent only with the EEI Master

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[70] Copies of the ISDA Master Agreement and associate Power Annex can be found on the website of the International Swaps and Derivatives Association, Inc., at www.isda.org.

Agreement. By modifying the *Pro Forma* REC Sales Confirmation to also allow for transactions under either the ISDA Master Agreement or the EEI Master Agreement, more parties will have the ability to easily participate in SCE's REC Sales RFOs in 2018.

8.13.2. The Written Plan

In the 2017 RPS Plan, SCE included information on its Residential and Non-Residential Time-of-Use (TOU) periods, in compliance with D.17-01-006 at 67. In its 2017 Final RPS Plan, approved by the Commission in D.17-12-007, SCE stated that "Going forward, Base TOU periods will be addressed in SCE's General Rate Case Phase 2 proceedings and consequently will not be included in subsequent RPS Plans." Accordingly, SCE has not included information on its Residential and Non-Residential TOU periods in this 2018 RPS Procurement Plan.

The next changes concern addition of information on electrification of transportation. D.18-05-026 implementing SB 350 provisions on penalties and waivers in the RPS program requires that: "Beginning with the 2018 Renewables Portfolio Standard Procurement Plan cycle, all retail sellers as defined in Public Utilities Code Section 399.12(j) must annually demonstrate that transportation electrification is accounted for in their procurement plans by explicitly referencing forecasted transportation electrification in their Renewables Portfolio Standard procurement plans…"[71] Accordingly, SCE states that it added a discussion of its forecast of transportation electrification in Section II.B of its 2018 RPS Procurement Plan, which discusses how SCE forecasts RPS need.

[71] D.18-05-026, OP 3 at 32.

Third, SCE made revisions to its REC sales strategy. In June of 2017, the Commission opened the PCIA OIR. SCE states that it did not have the opportunity to consider the impacts of that proceeding on its REC sales strategy in its 2017 RPS Procurement Plan. In its Draft 2018 RPS Procurement Plan, SCE presents a REC sales methodology that conforms to two possible scenarios for the outcome of the PCIA OIR. Because the final decision in the PCIA OIR (D.18-10-019) differs from the two possible scenarios for the outcome of the PCIA OIR that SCE presents, SCE may seek to update its 2018 RPS Plan to revise its REC sales strategies in conformance with the final PCIA OIR decision.

In addition, in this 2018 RPS Procurement Plan, SCE generally proposes sale of all PCCs of RECs, rather than just PCC 1, as it proposed in the 2017 RPS Plan in order to give SCE the flexibility to sell more types of RECs in the market. SCE also proposes to sell RECs for longer terms (if there is a market for such sales) and makes changes to its price floor methodology.

Finally, there is the addition of updated information to address SB 100. Consistent with the ALJ's E-Mail Rulings of September 19, 2018 and September 24, 2018, SCE has modified its Written Plan and provides replacements for Appendices A, C.1, C.2, C.3, C.4, C.5, C.6, C.7, and C.8 to SCE's 2018 RPS Procurement Plan to address new goals adopted in SB 100.

8.14. Safety Considerations[72]

SCE's 2018 *Pro Forma* provides that the seller must operate the generating facility in accordance with "Prudent Electrical Practices." The detailed definition of "Prudent Electrical Practices" includes "those practices, methods and acts that

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[72] SCE's 2018 RPS Procurement Plan at 59.

would be implemented and followed by prudent operators of electric energy generating facilities in the Western United States, similar to the Generating Facility, during the relevant time period, which practices, methods and acts, in the exercise of prudent and responsible professional judgment in the light of the facts known or that should reasonably have been known at the time the decision was made, could reasonably have been expected to accomplish the desired result consistent with good business practices, reliability and safety. . . ."

SCE's 2018 *Pro Forma* also provides that, prior to commencement of any construction activities on the project site, the seller must provide to SCE a report from an independent engineer certifying that seller has a written plan for the safe construction and operation of the generating facility in accordance with Prudent Electrical Practices.

SCE also has a safety section in its 2018 Procurement Protocol providing that sellers must possess a written plan for the safe construction and operation of the generating facility as set forth in the 2018 *Pro Forma*.

8.15. Standard Contract Option[73]

Since the Standard Contract Option is part of the RPS Solicitation, it will be utilized if SCE holds a 2018 RPS Solicitation. Consistent with the Commission's intent to provide the IOUs with flexibility to optimize their portfolios based on their procurement needs while providing a streamlined procurement tool, the Standard Contract Option will allow for rapid development of renewable projects by avoiding the contract negotiation process and expediting the Commission approval process of executed PPAs. The Standard Contract Option

[73] *Id.*, at 60-62.

will only be available to projects with a first point of interconnection to the CAISO, and not to dynamically scheduled projects.

Once executed, the Standard Contract Option PPAs will be submitted to the Commission for approval via a Tier 2 Advice Letter. This process uses the same approval process as in RAM, which was one factor in SCE successfully procuring 787 MW of renewables over five years in six auctions.

8.16. GTSR Program[74]

The GTSR program structure approved by the Commission consists of two elements: (1) a GT option (called the "Green Rate" by SCE) allowing customers to purchase energy with a greater share of renewables, and (2) an enhanced community renewables option (called the "Community Renewables" or "CR" program by SCE) allowing customers to subscribe to renewable energy from community-based projects.

SCE incorporated CR-related modifications into its 2016 Procurement Protocol, created a CR Rider and Amendment to the 2016 *Pro Forma* Standard Contract Option, and incorporated modifications to its LCBF Methodology for CR and CR-EJ eligible projects. SCE launched a Community Renewables Solicitation on April 7, 2017.

SCE incorporated additional CR-related modifications into its 2017 Procurement Protocol and updated its CR Rider and Amendment to the 2016 *Pro Forma* Standard Contract Option, which is the latest approved contract option. SCE subsequently launched its third and fourth Community Renewables Solicitations on December 22, 2017 and May 23, 2018, respectively. As of

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[74] *Id.*, at 62-68.

CR-RAM 3, SCE has provided two CR-RAM Rider options to offerors—one specifically for Distributed Energy Resources and the other for projects that do not aggregate resources.

On December 22, 2017, SCE filed a Tier 3 Advice Letter 3722-E requesting the Commission's approval to terminate the GTSR program on January 1, 2019,[75] and to seek approval to recover outstanding GTSR costs through the 2018 ERRA Review of Operations Filing.[76] SCE proposed a replacement program for GTSR in Advice Letter 3722-E. To date, the Commission has not approved Advice Letter 3722-E.

On June 21, 2018, the Commission approved D.18-06-027, Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities, which implements three new programs to promote solar energy in DACs. Two of the programs, the new DAC-Green Tariff program and the Community Solar GT program, are similar to the GTSR Green Rate and Enhanced Community Renewables programs, respectively. The DAC – Green Tariff Program will be available only to low-income residential customers in DACs, defined as those meeting the qualifications for California Alternate Rates for Energy and Family Electric Rate Assistance. The Community Solar Green Tariff Program will be similar to the DAC - Green Tariff program. The major difference between the DAC-Green Tariff program and the Community Solar Green Tariff program is that the Community Solar Green Tariff program requires community involvement with the solar project through a local sponsor and will result in a solar facility serving a nearby community. The program is

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75 *See* D.15-01-051 at OP 13.

76 Advice Letter 3722-E.

similar to Enhanced Community Renewables in that the developer contracts with the customer to service the energy component of the bill and contracts with SCE for the energy not subscribed by the SCE customer. SCE's Advice Letter for implementation of the DAC-Green Tariff and Community Solar Green Tariff Programs was filed on August 20, 2018. After Commission disposition of the Advice Letter, the details of the procurement addressed in that Advice Letter can be incorporated in any updated RPS Plan.

8.17. Other RPS Planning Considerations and Issues[77]

8.17.1. Bilateral Transactions

As part of its overall procurement strategy, SCE states that it may engage in bilateral negotiations for renewable energy purchases or sales subject to the Commission's review and approval of completed transactions. As noted above, SCE proposes to not hold an annual RPS procurement solicitation based on RPS need. Thus, SCE must seek permission from the Commission to prior to any procurement, other than amounts separately mandated by the Commission.

8.17.2. Energy Storage Procurement

SCE considers eligible energy storage systems to help meet its energy storage target through several different programs including conducting an Energy Storage RFO, the Aliso Canyon Energy Storage RFO and other programs that may incorporate energy storage facilities. Further details on SCE's energy storage procurement can be found in SCE's Energy Storage Plan.

[77] SCE's 2018 RPS Procurement Plan at 68.

9. SDG&E 2018 RPS Plan

9.1. Summary[78]

SDG&E states that its 2018 RPS Procurement Plan describes the processes used to determine its RPS procurement need, as well as the methods it will use to manage its RPS portfolio to meet RPS program compliance targets. SDG&E claims that its RPS Procurement Plan establishes guidelines for SDG&E's procurement of LCBF RPS-eligible resources that have enabled and will enable SDG&E to achieve its procurement need in each compliance period (CP). To determine the quantity of renewable generation that must be procured, SDG&E will follow a Need Determination Methodology which is discussed below.

On October 8, 2018, SDG&E updated its 2018 RPS Plan to discuss the impact of the passage of SB 100.

9.2. Assessment of RPS Portfolio Supplies and Demand[79]

9.2.1. Need Determination Methodology

SDG&E states that it makes procurement decisions based on how its risk-adjusted RPS position forecast (referred to herein as its RPS position) compares to its RPS program compliance requirements, the result of which is its probability-weighted procurement need or RNS. In order to calculate its RPS position, SDG&E assigns a probability of success, following a qualitative and quantitative assessment, to the expected deliveries for each project that is not yet online in its portfolio and then adds the risk-adjusted expected deliveries across all projects in its entire RPS portfolio.

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[78] SDG&E's 2018 RPS Procurement Plan, August 20, 2018, updated on October 8, 2018, at 1-3.

[79] *Id.*, at 3-28.

In general, if SDG&E's RPS Position is less than its RPS requirements, SDG&E will plan to procure additional RPS resources on a schedule that will allow for the procurement and development of resources in time to provide deliveries to meet anticipated shortfalls. If, on the other hand, its RPS Position is greater than its RPS requirements, SDG&E will consider opportunities to bank or sell bundled and/or unbundled RECs. In addition, to optimize the relative value of renewable energy across compliance periods, SDG&E also considers short-term contracts when, for example, it is short[80] in the most immediate CP but long in the subsequent CP. SDG&E will also consider procurement strategies that are in the best interest of customers across compliance periods in order to secure greater value from approved RPS expenditures. For example, SDG&E strives to have a well-diversified RPS portfolio so that its RPS compliance, particularly in the most immediate compliance period, is not unduly exposed to any given risk (*e.g.*, a particular technology, region, counterparty, etc.). SDG&E's RPS portfolio management strategy involves identifying needs and risks and managing them in a cost-effective manner in the best interest of its customers.

9.2.2. Portfolio Optimization Strategy

Once SDG&E has determined the probability of success for each of the contracts in its portfolio, SDG&E states that it evaluates the impact of certain risk factors that can impact individual projects or the entire portfolio. These factors, which include, but are not limited to the following which SDG&E evaluates on a monthly basis: (i) Retail Sales; (ii) RPS Program Rules; (iii) Project Viability;

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[80] The term "short" is used herein to refer to an RPS Position that is lower than the relevant RPS program requirements. The term "long" is used to refer to an RPS Position that is higher than relevant RPS program requirements.

(iv) Existing RPS Contracts; (v) Policy Procurement; and (vi) Other Procurement Authorizations.

9.2.3. Lessons Learned

SDG&E first discusses overbuilding and its impact on ratepayers. As described in all RPS Plans since 2013, SDG&E is concerned that developers provided profiles in prior solicitations that did not match the profiles of the facilities that were ultimately built.[81] In other words, developers "overbuilt" facilities (*i.e.*, installed capacity above the amount bid and/or shaped the production profile to take advantage of higher-priced TOD periods). The resulting overgeneration has increased costs to customers through increased contract costs, and increased generation overall which increases the incidence of and payments for negative real-time energy pricing. SDG&E has modified its PPA several times to discourage this practice going forward, and will continue to reevaluate its contract provisions in subsequent versions of the plan, as new information becomes available, to determine if and how its contracts should be updated.[82]

Next, SDG&E addresses peak shifting. Due to the success of the RPS program, a significant amount of renewable energy continues to be added to the grid. Substantial amounts of rooftop solar are also being added by customers behind the meter. As a result, the peak load net of variable energy resources has and will continue to shift as the California resource portfolio evolves. Renewable

[81] SDG&E 2013 RPS Procurement Plan at 37. SDG&E 2014 RPS Procurement Plan at 25. SDG&E 2015 RPS Procurement Plan at 25. SDG&E 2016 RPS Procurement Plan at 28. SDG&E 2017 RPS Procurement Plan at 31.

[82] SDG&E 2013 RPS Procurement Plan at 38. SDG&E 2015 RPS Procurement Plan at 25-28.

resources have low variable costs, and at high penetration levels during any single time during the day, may result in significant decreases in marginal energy prices and even significant ramping events. As market conditions develop, it is important that SDG&E's TOD factors and time periods, which will be used for analysis purposes, reflect the most up-to-date information to provide customers with the greatest value. SDG&E has, and will continue to update its TOD factors as market conditions evolve.

Third, SDG&E identifies capacity value. SDG&E's method for calculating energy and capacity values uses a benchmark where energy values are shaped hourly based on a forecast of SP15 energy prices and the results of production cost modeling that yields a year 2022 hourly energy shape. The capacity value is shaped hourly using a year 2022 Loss-of-Load Probability (LOLP) study. The process assigns higher capacity value to hours of greater capacity need, which more accurately reflects the impact of variable energy resources upon capacity needs. The calculation provides annual capacity values for both local and Imperial Valley (IV)/System area projects.[83] These annual values are then taken through a process which creates monthly capacity values using the LOLP mentioned above, then down to an hourly level using the monthly values.

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[83] For Local Area Projects: the Marginal Generation Capacity Cost of $120/kW-year, which is intended to provide a proxy for the net cost of new entry, as discussed in Section 3 of the Revised Prepared Direct Testimony of David T. Barker, Chapter 5, On Behalf of SDG&E in connection with Application 11-10-002 (Application of SDG&E For Authority To Update Marginal Costs, Cost Allocation, And Electric Rate Design). Note that this value will need to be updated from time to time in correlation with market trends. The current value of $120/kW-year is in 2012 dollars and a 2.5% annual escalation rate is applied to calculate the value beyond 2012.

For IV Area Projects and System Area Projects: the CPUC penalty of $40/kW-year associated with failure to meet system RA requirements. CPUC 2014 Filing Guide for System, Local and Flexible RA Compliance Filings at 27.

SDG&E believes these benchmark values are reasonable because, when evaluating a contract on a standalone basis, it should be measured against the avoided costs the utility might face had this contract not been part of the portfolio. For example, if SDG&E had a resource in its portfolio, and that resource was crucial to meeting local resource adequacy requirements, the marginal value of that resource is the amount that SDG&E must pay to replace that resource if it becomes unavailable plus the cost to replace the energy that resource would have generated in order to serve hourly retail load. SDG&E will update its calculations as the assumption sources are updated.

Finally, SDG&E is concerned that a facility could reach commercial operation prior to the contractual commercial operation date (COD), but delay declaring COD until the COD date in the contract. As a result, the facility would be paid for this energy at the contract price, thereby extending the term of its contract, resulting in an additional cost to customers. To mitigate this issue, SDG&E revised its PPAs several years ago to change the price paid for energy delivered prior to COD to a fixed REC value plus CAISO revenues net of CAISO costs.

9.2.4. Trends

As the market for renewable energy has matured, SDG&E states that it has observed a positive trend in the project success rate. SDG&E reviews project success rates on a monthly basis to incorporate the most recent information and will continue this practice.

SDG&E highlights four of those trends. First, there is the RA program. The Commission adopted multi-year Local RA requirements in D.18-06-030, issued on June 25, 2018. Currently, the Local RA requirements are only for one compliance year. Beginning in 2020, LSEs will have a minimum of 3 years of Local RA requirements.

Second, SDG&E identifies multiple RPS contract versions across programs. SDG&E has noted that as the volume of mandated programs has increased, so have the number of contract versions that must be managed. At this time, there are five distinct PPAs for RPS products, all with separate approval processes: the Long-Term and Short-Term RPS PPAs (attached to its 2018 RPS Procurement Plan as Appendices 6 and 7), the GT RAM PPA (attached to its 2018 RPS Procurement Plan as Appendix 11.A), the Enhanced Community Renewables (ECR) RAM PPA Rider (attached to its 2018 RPS Procurement Plan as Appendix 12.A), and the BioMAT PPA. As the Commission has acknowledged, it is logical that the TOD factors used in each PPA be consistent, to the extent possible.[84] Going forward, in accordance with D.14-11-042, SDG&E intends to use the TOD factors approved in each RPS Plan in all PPAs for RPS products executed in that plan year, with updates where appropriate. Additionally, any Tier 1 Advice Letter filed by SDG&E requesting Commission approval of conforming TOD factors across its RPS Procurement Programs will be served on the R.18-07-003 service list, or then current RPS proceeding, and any entities in SDG&E's RPS procurement queue.[85]

Third, SDG&E discusses Integrated Resource Planning (IRP). According to SDG&E, SB 350 added a provision to the Public Utilities Code directing the Commission to implement a holistic integrated resource planning process. IRP is a wide-ranging effort at the Commission, undertaken along with staff from the

[84] D.14-11-042 at 24.

[85] D.15-12-025, OP 7 at 123.

CEC and the California Air Resources Board (CARB), that will/should combine the numerous planning processes currently undertaken in separate resource-specific cases into a single look to ensure that IOU and non-IOU load-serving entities will achieve the targets to be established by CARB related to GHG emission reductions.[86] SDG&E looks forward to participating in the resolution of these items and the development of the IRP process, with the end goal of enhancing the cost-effectiveness of RPS and other procurement mandates. SDG&E believes that it is prudent to pause any incremental RPS-procurement, including the adoption of new procurement mandates, while IRP is being implemented, especially given SDG&E's RPS performance to date.

Finally, SDG&E discusses the need to meet the demand for higher levels of renewables. In addition to the State's goals (the most recent development of which was SB 350), many customers and communities within SDG&E's service territory are interested in electricity service with even higher levels of renewables than required by law. Related to SDG&E's RPS planning efforts, SDG&E will consider ways in which SDG&E can potentially provide offerings that are made available to customers throughout the SDG&E service territory to help meet these goals.

9.3. Project Development Status Update[87]

SDG&E states it evaluates project development status to assess each project's ability to begin deliveries pursuant to contract terms and conditions. SDG&E's portfolio of renewable energy resources currently under contract but

[86] SB 350 (Stats. 2015, Ch. 547) at 14.

[87] SDG&E's 2018 RPS Procurement Plan at 29-31.

not yet delivering (either pre-construction or in construction) are in various stages of development. SDG&E has or is developing contracts for five renewable projects that are in the pre-construction or construction phase (none of which are utility-owned generation (UOG) and 61 projects that are in commercial operation (12 none of which are UOG). Information regarding these projects, including the following data points requested by the ACR, can be found in Appendix 2 to SDG&E's 2018 RPS Procurement Plan: (i) name; (ii) capacity; (iii) term; (iv) location; and (v) COD. In SDG&E's estimation, projects in the pre-construction phase are most at risk of failure. However, projects under construction may also encounter issues that could affect their ability to achieve commercial operation, such as successful litigation against the project. In general, projects that have achieved commercial operation have a high probability of meeting their contractual obligations; however, project failure or resource fluctuations (*i.e.*, a bad wind year) can create challenges. Although a developer's experience may improve the likelihood of a project achieving commercial operation, it does not ensure that a project will be successful. Sections II, IV and V of its Plan discuss the various delays and risks that could impact projects in various stages of development, and Appendix 1 of its 2018 RPS Procurement Plan provides information on SDG&E's developing projects from SDG&E's June 2018 PRG meeting.

9.4. Potential Compliance Delays[88]

Similar to prior RPS plans, SDG&E identifies seven potential factors that can impact project development and the eventual attainment of RPS program

[88] *Id.*, at 31-38.

goals: (1) transmission and permitting; (2) project finance, tax equity financing, and government incentives; (3) debt equivalence and accounting; (4) regulatory factors affecting procurement; (5) unanticipated curtailment; (6) insufficient supply of renewable resources; and (7) unanticipated increases in retail sales. SDG&E states that these factors contribute to SDG&E's monthly Assessment of the likelihood of each project's success. For example, a project that has been experiencing difficulty in obtaining a key permit would receive a probability weighting reduction to account for this risk until the issue is resolved. While the impacts of the regulatory proceedings cannot be known until the final decisions are issued, SDG&E states it is monitoring these issues and will reflect their outcomes accordingly, when appropriate. The results of these cumulative assessments are reflected in the RNS, which SDG&E will use to inform its procurement activities. The RNS as of August 2018 is provided in Appendix of its 2018 RPS Procurement Plan.

9.5. Risk Assessment[89]

Similar to prior RPS plans, SDG&E identified several "dynamic factors" outside of SDG&E's control that could impede progress towards achieving RPS goals:

- Resource Availability and Variable Generation: Renewable resources depend on natural sources of energy which are variable, and can be impacted by various factors. For example, a bad wind year can greatly impact a wind facility's performance and cause lower than expected generation. Another factor that could also impact generation is the occurrence of unexpected mechanical failures, which could cause a facility to be partially or fully unavailable until the issue can be resolved.

[89] *Id.* at 38-40.

- Regulatory Changes: The expiration of subsidies or additional requirements resulting from changes in regulations could lower the revenue stream and increase costs for RPS developers and could lead to reduced production if the project has difficulty in supporting this lower revenue stream.
- Economic Environment: The interest rates and flexibility of financing arrangements entered into by developers can impact a project's success. Long-term project financing arrangements with unfavorable terms can lead to project failure or reduced production if the project has difficulty in supporting the financing cost requirements. Additionally, economic factors that negatively impact a generator's supply chain could impact its ability to comply with contract terms.
- Evolving Technology: Facilities with older generation technology that is no longer supported by the manufacturer can experience project failure or reduced production. This problem is arising now for older RPS projects, and could occur in the future as the projects built today begin to age.
- Issues with Third Party Mandatory Systems: CAISO and WREGIS systems have experienced technical issues in the past, and potential technical problems with these systems going forward could complicate the compliance process.

SDG&E's current Assessment is that, as an overall matter, projects in its portfolio are at a low risk of non-performance, but notes that this Assessment is based on the above risk factors remaining relatively stable. That being said, SDG&E states that it does not anticipate any compliance delays at this time.

9.6. Minimum Margin of Over-Procurement[90]

SDG&E's RPS Risk Adjusted RNS Calculation, as shown in Appendix 2 to SDG&E's 2018 RPS Procurement Plan, provides a VMOP. SDG&E's VMOP is

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90 *Id.*

composed of a "Minimum Margin of Procurement" that is intended to account for foreseeable project failures or delays, as well as an additional volume of procurement which is undertaken to ensure that SDG&E achieves its RPS requirements despite unforeseeable risks. Due to fluctuations in RPS targets (as a result of changes in retail sales) and RPS deliveries, SDG&E believes it is nearly impossible to meet RPS targets with the exact number of MWhs required. SDG&E's VMOP is designed to ensure that it achieves its RPS goals in consideration of foreseeable and unforeseeable risks.

Because it is difficult to predict retail sales and project performance, particularly for periods farther into the future, SDG&E's VMOP may be higher in later years. SDG&E's portfolio (RPS resources necessary to reach compliance and provide a VMOP) is the result of the forecasts (including need, retail sales, and project success rates), the assessment of potential risks, and the project valuations made at the time of each individual contract execution and approval.

9.7. Bid Solicitation Protocol, Including Least-Cost, Best-Fit[91]

Attached to its 2018 RPS Procurement Plan at Appendices 7-12.B are SDG&E's proposed RPS Long- and Short-Term Model PPAs, RPS REC Agreement, LCBF, RPS Sales RFP, RPS Sales Model PPAs, documentation for a GT RAM solicitation, and documentation for an ECR RAM solicitation. Although SDG&E does not intend to issue a solicitation for RPS purchases in 2018, it has attached RPS Long- and Short-Term Model PPAs, an RPS REC Agreement, and an LCBF document. Submitting these updated documents is important so that they do not become stale. As required by D.14-11-042, SDG&E

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[91] *Id.*, at 41-43.

has included GT RAM and ECR RAM solicitation documents. Per D.14-11-042, SDG&E will request Commission approval via a Tier 1 Advice Letter if it determines that changes to these documents are necessary.

9.7.1. Workforce Development Assessment Proposal

A Workforce Development Assessment is included as a qualitative factor within SDG&E's LCBF. The information used in this Assessment will be gathered as part of the required bid information for any solicitations which include renewable resources. The Assessment results will be qualitatively compared among all renewable resource bids within the solicitation which will inform the final bid ranking, similar to all other qualitative factors.

9.7.2. Assessment of Benefits to Disadvantaged Communities

In D.04-07-029, the Commission directed the use of "benefits to low income or minority communities" as a qualitative factor in the LCBF analysis. Consistent with this direction, SDG&E states it has applied this factor on a qualitative basis along with several other qualitative factors (see Appendix 9 to its Plan for a full list). Benefits to the community are either described by the developer in the project description form, or can be requested by SDG&E if not provided. The results of SDG&E's LCBF analysis (quantitative as well as any additional qualitative) are shared with the PRG and also described in the Advice Letter seeking approval for SDG&E's shortlist.

9.8. Consideration of Price Adjustment Mechanism[92]

SDG&E acknowledges that contracts with online dates occurring more than 24 months after the contract execution date can pose additional risk to customers. SDG&E has incorporated price adjustment mechanisms into some of its current contracts that are intended to alleviate some of these risks, including the following:

- <u>Price adjustment for delay in Guaranteed Commercial Operation Date (GCOD)</u>: A lower price for a late GCOD provides an additional incentive for developers to come online pursuant to the contract. However, this structure can create financing challenges if financing parties are not comfortable with the potentially lower price. It is also difficult to quantify an appropriate price adjustment amount and can lead to drawn out negotiations.
- <u>Capped transmission upgrade costs</u>: Placing a cap on the amount of transmission upgrade costs, which are ultimately borne by customers, that a project can incur is, in SDG&E's estimation, an effective way to limit customer exposure to such costs. This type or cap is important for projects that do not yet have an executed interconnection agreement, because there is some chance that transmission upgrade cost estimates could change for these projects. The cap is set as a condition precedent to SDG&E's obligations under the PPA. If estimated upgrade costs exceed the cap, SDG&E has the right not to move forward with the PPA.
- <u>Price adjustment for higher than expected transmission upgrade costs</u>: Another mechanism that SDG&E has incorporated into past contracts is a mechanism whereby the seller agrees to a price reduction to offset higher than anticipated transmission upgrade costs. Under this mechanism, the contract price would be

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[92] *Id.* at 43-44.

reduced on a dollars per megawatt-hour basis commensurate with the cost of transmission network upgrades above an agreed upon cap. The price adjustment mechanism would include an upper limit on transmission upgrade costs, above which SDG&E can terminate the contract. This mechanism is similar to the cap described immediately above except, rather than giving SDG&E the right not to move forward with the PPA, it gives the developer the choice of to either proceed at a reduced price equal to the amount of transmission costs above the cap, or not go forward with the PPA. If the developer chooses the lower price, that lower price acts as a funding mechanism for the additional upgrades, thereby adhering to the projected total customer costs.

- Price adjustment for failure to achieve full capacity deliverability status: If a project is not deemed fully deliverable by CAISO at the time of COD, then the PPA price is reduced either through a negotiated amount, or the application of energy only TOD factors in place of FCDS factors until such time as the project is deemed fully deliverable.

9.9. Economic Curtailment Frequency Costs, and Forecasting[93]

In SDG&E's estimation, the issue of curtailment is a result of the operational characteristics of the facilities within the renewable market. These resources are as-available (that is, they generate only when the wind is blowing or the when sunlight strikes the panel, and they are negatively affected by atmospherics which interfere with this energy production, such as cloud cover) and intermittent, which results in generation profiles that do not necessarily follow load. SDG&E's net load profile now shows a pronounced shift toward an evening peak as increased solar generation has begun to offset load during SDG&E's historical peak load hours (mid-day). The shift of SDG&E's net peak

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93 *Id.*, at 44-49.

into the evening hours becomes more pronounced as more renewable generation (particularly solar) is brought online, as it has over the past several years and will continue to do so as RPS penetration increases.

SDG&E states it has been tracking its curtailment actions and results since Q3 2014, and based on the data available to date, its curtailment activities have resulted in cost savings for SDG&E customers. SDG&E will continue to track this data and report on it.

SDG&E has undertaken activities to manage its existing contracts, as well as strengthen the language regarding economic curtailment in its pro forma PPA to be used in future contracting.

Beginning with its existing contracts, SDG&E states it has seen multiple instances of negative pricing since the CAISO implemented its new tariff revisions on May 1, 2014, and has acted to minimize customer exposure by economically curtailing facilities with which it has this contractual right. These instances have generally followed the same sequence of events: (a) as facility Scheduling Coordinator, SDG&E economically bids energy from a facility into the market; (b) a negative pricing event occurs; (c) the CAISO instructs the facility that was economically bid by SDG&E to dispatch down (curtail); and (d) the facility responds to the extent possible. These actions protected customers by reducing the negative pricing payments made to the CAISO, but SDG&E's ability to curtail its current portfolio is limited by several factors: (a) a few of SDG&E's existing RPS contracts do not contain economic curtailment rights (however, as mentioned below, SDG&E has initiated contract renegotiations minimizing adverse impacts on customers); (b) some facilities have operating restrictions which impact their ability to respond immediately to an economic curtailment order; and (c) (where the contract contains economic curtailment rights) SDG&E's ability to economically curtail is limited in cases to 5% of a facility's annual deliveries. SDG&E continues to work with counterparties, where possible, to reduce the number of cases where these limitations apply.

SDG&E also states that it has continued renegotiation of dispatch down, scheduling and curtailment provisions of existing contracts. To the extent feasible, SDG&E plans to address all contracts that require updates due to CAISO's implementation of Federal Energy Regulatory Commission (FERC) Order 764, including RAM legacy contracts to the extent the Commission has previously approved such provisions in the most recent RAM VI PPA. SDG&E's PPAs (including RAM legacy contracts) generally contain language which contemplates the need for the buyer and seller to update the PPA when there are major market changes (such as CAISO's implementation of FERC Order 764).

Finally, SDG&E states that its 2018 RPS Procurement Plan contains an overview of SDG&E's procurement strategy, including ways to address the economic curtailment observations and activities discussed in this section. On the evaluation side of procurement, work to revise the LCBF and incorporate a final integration adder is underway at the Commission, and until this adder is finalized SDG&E will utilize the interim integration adder adopted in D.14-11-042. With respect to the contract side of procurement, SDG&E incorporated provisions into its PPA in the 2014 version of its RPS Plan related to curtailment and is working on the renegotiation of dispatch down and scheduling and curtailment provisions in its remaining existing contracts that have not already been amended for economic curtailment. SDG&E also made additional modifications to its RPS PPAs (attached as Appendices 6, 7, and 11.A to its 2018 RPS Procurement Plan) to ensure clarity with respect to FERC 764 changes in its 2016 RPS Plan, and as explained above, has made contract adjustments intended to remove the incentive to overbuild (additional and unplanned generation can contribute to negative pricing incidences and lead to economic curtailment).

Initiatives undertaken outside of the RPS proceeding also have the potential to assist in the management of intermittent generation and the resulting curtailment – specifically, the addition of flexible capacity and energy storage resources to the grid. On May 21, 2015, the Commission approved SDG&E's 20-year term contract with the Carlsbad Energy Center in D.15-05-051, finding that "[t]he Carlsbad PPTA would provide additional benefits including reliability benefits by being able to meet SDG&E's LCR need by 2018, renewable resources integration benefits due to its flexible dispatchability, and locational benefits by virtue of being highly compatible with the existing transmission system and on previously disturbed land."[94] The Commission's decisions on storage (D.13-01-040, D.14-10-045 and D.16-01-032) list a myriad of grid management issues that can be addressed via storage, for example, transmission and distribution reliability.[95] Storage also has the ability to respond to periods of overgeneration by adding storage system charging load during overgeneration periods, potentially mitigating the frequency of negative pricing. SDG&E is well on its way to meeting the energy storage procurement requirements included in D.13-01-040 including the procurement of at least 165 MW[96] of energy storage through a series of biannual solicitations. To date, SDG&E states it has

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[94] D.15-05-051 at 34.

[95] D.13-10-040 at 15.

[96] D.13-10-040 at 15.

completed the 2014, 2016 and 2018 energy storage procurement cycles and may hold another solicitation in 2020 if necessary. Additionally, D.14-03-004 required that SDG&E procure a minimum of 25 MW[97] of energy storage, and in A.17-04-017, filed by SDG&E on April 29, 2017,[98] SDG&E made a showing that this requirement has been fulfilled.

SDG&E claims to have 37.5 MW of battery energy storage on-line-Escondido (30 MW) and El Cajon (7.5 MW). Both facilities participate in the CAISO market. SDG&E states that it anticipates increasing battery storage project participation in the CAISO market in the next couple of years.

9.10. Cost Quantification[99]

Appendix 3 to SDG&E's 2018 RPS Procurement Plan provides an annual summary of both actual and forecasted RPS procurement costs and generation, by technology type, as of June 2018.

9.11. Imperial Valley[100]

SDG&E states that although it did not hold a 2017 RPS RFO, the RPS portfolio currently contains 12 contracts in the IV/IID territory, that when completed will provide an estimated 3,100 GWh per year. As of June 2018, 10 of these projects have reached commercial operation, and the generation from these projects is anticipated to be approximately 3,000 GWh per year. Additionally, pursuant to approved Advice Letter 2717-E, projects located within the IV and either directly connected or dynamically transferred via pseudo-tie into SDG&E's

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97 D.14-03-004 at 2.

98 Approved by the Commission in D.18-05-024.

99 SDG&E's 2018 RPS Procurement Plan at 49.

100 *Id.*

service territory by the CAISO are eligible to participate in SDG&E's GTSR program. Currently SDG&E has two GT projects in development in the IV with total estimated generation of 116 GWh per year. Likewise, the GTSR Phase IV decision allows ECR facilities that contract with SDG&E to site in the IV.

9.12. Important Changes to the Final 2018 RPS Procurement Plan[101]

Important changes made to SDG&E's Final 2018 RPS Procurement Plan are detailed in Appendix 5 of the 2018 RPS Procurement Plan.

9.13. Safety Considerations[102]

SDG&E states it is committed to providing safe, reliable and environmentally sound electric service for its customers. As discussed in Appendix 4, SDG&E's RPS Procurement Plan contemplates procurement of RPS-eligible generation through both PPAs and UOG. SDG&E's emphasis on safety is reflected in: (i) the terms and conditions contained in the pro forma PPAs used in its various procurement programs; and (ii) the safety procedures that all contractors working on UOG facilities are required by SDG&E to follow.

9.14. Renewable Auction Mechanism[103]

SDG&E anticipates meeting its CP3 need with projects it already has under contract. Consequently, SDG&E may use the RAM solicitation documentation, attached hereto as Appendices 11-12.B, on an as-needed basis to procure for its GTSR program, as authorized by D.15-01-051 and D.16-05-006. Attached are the most recently approved RAM documents, which are intended for procurement

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[101] *Id.*, at 49-50.

[102] SDG&E's 2018 RPS Procurement Plan at 50.

[103] *Id.*, at 50-52.

of resources for the GT component of SDG&E's GTSR program, as well as for the ECR component of SDG&E's GTSR program. On June 21, 2018 the Commission approved D.18-06-027 adopting two new programs based on the GTSR program to grow solar in DACs, DAC-Green Tariff and Community Solar Green Tariff. SDG&E is required to procure new solar resources for these programs based on the structure of the underlying GTSR program; SDG&E will seek approval for solicitation documents, PPA and Rider once program implementation has been approved by the Commission.

SDG&E has attached GT RAM solicitation form documentation hereto as Appendices 11-11.B to its 2018 RPS Procurement Plan. These documents are summarized below:

- Appendix 11, GT RAM RFO: This document incorporates the eligibility criteria required by D.14-11-041, D.15-01-051, and D.16-05-006: allows for all RPS-eligible projects to participate in the program, allows for projects to be sized 0.5 MW to 20 MW, allows projects to be located in, or dynamically transferred into, SDG&E's territory (which is within the CAISO), requires at a minimum a Phase II Interconnection Study for projects interconnecting at the transmission level (and equivalent requirements for projects interconnecting at the distribution level), requires a 36 month construction timeline, which may be extended up to 6 months for interconnection, force majeure and/or regulatory delays, and requires the submittal of a Geographic Information System (GIS) file of the project boundaries and associated gen-tie. SDG&E will use its RPS LCBF methodology, attached hereto as Appendix 9, to evaluate projects that bid into future RAM auctions.[104]

[104] D.14-11-042 at 23, 66, 94-101.

- Appendix 11.A, GT RAM PPA: SDG&E's GT RAM PPA is a modified version of the RAM PPA and includes the additional eligibility criteria required by D.15-01-051 and D.16-05-006.
- Appendix 11.B, GT RAM Offer Form: SDG&E's GT RAM Offer form, attached hereto as Appendix 11.B, is compatible with its LCBF methodology, attached hereto as Appendix 9. The GT Projection Description form has been consolidated into the GT RAM Offer form.

SDG&E has attached ECR RAM solicitation form documentation hereto as Appendices 12-12.B to its 2018 RPS Procurement Plan. These documents are summarized below:

- Appendix 12, ECR RAM RFO: This document incorporates the following eligibility criteria required by D.14-11-042, D.15-01-05,[105] D.16-05-006[106] and D.17-07-007[107] allows for projects to be sized 0.5 MW to 20 MW, allows for distributed energy resource providers to aggregate, allows projects to be located in, or dynamically transferred into, SDG&E's territory (which is within the CAISO), requires at a minimum a Phase II Interconnection Study for projects interconnecting at the transmission level (and equivalent requirements for projects interconnecting at the distribution level), requires a 36 month construction timeline, which may be extended up to 6 months for interconnection, force majeure and/or regulatory delays, requires the submittal of a GIS file of the project boundaries and associated gen-tie diagrams, and a securities opinion. SDG&E will use its RPS LCBF methodology, attached hereto as Appendix 9, to evaluate projects that bid into future RAM auctions.

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[105] D.15-01-051 OP 5 at 180.

[106] D.16-05-006 OP 1 at 41.

[107] D.17-07-007 OP 1 at 15.

- Appendix 12.A, ECR RAM Rider: SDG&E's ECR RAM Rider was designed to modify the GT RAM PPA pursuant to D.16-05-006 to procure RPS-eligible capacity for the purpose of implementing the ECR program. Pursuant to D.16-05-006, SDG&E is authorized to use the RAM to procure RPS-eligible capacity for the purposes of implementing the ECR program.
- Appendix 12.B, ECR RAM Offer Form: SDG&E's ECR RAM Offer form, attached hereto as Appendix 12.B, is compatible with its LCBF methodology, attached hereto as Appendix 9. The ECR Projection Description form has been consolidated into the ECR RAM Offer form.

9.15. Green Tariff Shared Renewables Program[108]

SB 43, which became effective on January 1, 2014, requires participating utilities to file an application for a Green Tariff Shared Renewables (GTSR) program allowing customers to buy some or all of their energy from local renewable projects via a GT or ECR program. The ultimate GTSR program was implemented through a series of Commission Decisions as well as implementation ALs submitted by the IOUs. SDG&E has launched GTSR solicitations for GT and ECR projects in July 2015, September 2016, March 2017, November 2017, and June 2018.

SDG&E has a target of 59 MW total capacity between its GT and ECR programs, and within this target are two reservations of 10 MW each for residential customers and Environmental Justice (EJ) projects.[109] The Commission has approved 42.4 MW of procurement in SDG&E's GTSR program. See Advice Letter 3074-E and Advice Letter 3214-E.

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108 SDG&E's 2018 RPS Procurement Plan at 52-54.

109 D.15-01-051 at 5.

Subsequent procurement for the GT program through RAM, as described in Section XV of SDG&E Plan, will be based on assessment of "incremental customer enrollments and the amount of dedicated Green Tariff procurement… [already] under contract."[110] SDG&E also submitted Advice Letter 3168-E to the Commission in December 2017, seeking to extend its GT and ECR programs through 2023 and to propose changes to the ECR program, such as solicitation timing and community interest requirements. A draft resolution has not yet been issued.

9.16. Other RPS Planning Considerations and Issues[111]

In accordance with D.17-08-030, SDG&E is including in its Plan information on its base time of use (TOU) periods. SDG&E's base TOU periods are established as part of the rate design proceeding commonly referred to as the General Rate Case Phase 2 (GRC Phase 2).

10. Comments on the 2018 RPS Procurement Plans

As noted above, a number of parties submitted opening and reply comments on the 2018 RPS Procurement Plans. Many parties commented on whether or not the Commission should order additional RPS procurement beyond that necessary to meet the LSEs' current compliance obligations.

IEP, ACC, and LSA argued that early procurement of RPS-eligible resources would be more cost-effective due to the declining federal tax credits.[112] IEP and ACC each included analysis with their comments illustrating the

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110 Advice Letter 3218 at 8.

111 SDG&E's 2018 RPS Plan at 54.

112 *See, e.g.*, IEP *Comments* at 3-11; LSA *Comments* at 1-12; ACC *Comments* at 6-9.

assumptions and cost savings. IEP showed that 1,000 MW of near-term procurement could result in savings from approximately $600 – $1 billion over the span of a 20-year contract for wind and solar, respectively.[113] The analysis put forward by ACC showed average savings from the production tax credit of approximately $700 million over the span of a 20 year contract for wind.[114] IEP and ACC also question whether CCAs are planning appropriately for load migration from the IOUs, and they view advanced procurement as a reasonable way to ensure incremental renewable resources are available for retail sellers to achieve the state's GHG reduction goals. In light of forecasted IOU departing load, IEP recommends that the cost and benefits of advanced procurement be allocated using a non-bypassable charge while the Power Charge Indifference Adjustment (PCIA) mechanism is under review in R.17-06-026.

The IOUs, CCAs and ORA conversely argued that the IOUs have a surplus of resources under contract to meet RPS procurement requirements and that any questions concerning advanced procurement should be investigated in the IRP proceeding.[115] The IOUs strongly recommended against the idea of any advanced procurement based on two reasons: "preliminary" modeling in the IRP proceeding and lack of an updated cost recovery mechanism for departing load.[116] Parties also commented on the need for the Commission to both complete the review and determination of LSEs' compliance waiver requests for

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113 *See, e.g.,* IEP *Comments* at 11.

114 *See, e.g., ACC Comments* at 8-9.

115 *See, e.g.*, ORA Reply Comments at 2-6, 8-9; PG&E *Reply Comments* at 1-7.

116 *See, e.g.,* PG&E *Reply Comments at 6-8;* SCE *Reply Comments at 3-6;* SDG&E *Reply Comments at 3-4, 6.*

the first compliance period (2011 – 2013) and implement an RPS Procurement Expenditure Limitation.[117] The Commission is currently reviewing both the LSEs' waiver requests and options for implementing the Procurement Expenditure Limitation, though we do not find that completing these activities is a predicate to reaching a decision on the merits of requiring additional RPS procurement.

Parties correctly point out that the consideration of near-term or advanced procurement is raised both here in the RPS proceeding and the IRP proceeding (R.16-02-007).[118] We appreciate the urgency as well as the caution expressed by the parties on this issue. While we take no action in this decision, the Commission is closely examining the arguments for and against near-term procurement. With the approval of the 2018 RPS Procurement Plans, the IOUs are well prepared to issue a solicitation for incremental renewables should the Commission find such actions reasonable.[119]

11. Conclusion Regarding the Investor-Owned Utilities' 2018 Procurement Plans

11.1. PG&E's 2018 RPS Procurement Plan

We find that PG&E's 2018 RPS Procurement Plan satisfies the specific requirement for the 2018 RPS Procurement Plans, which were set forth in the *2018 ACR*, and that PG&E's evaluation of its current RPS procurement needs

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[117] *See, e.g.*, ORA *Comments* at 2, 7-8; SCE *Reply Comments* at 6-7; SDG&E *Reply Comments* at 9.

[118] In addition to being raised in parties' comments in response to the IOUs' RPS Plans, the potential value of near-term renewable procurement was discussed during an all-party meeting in the IRP proceeding (November 2, 2017). Materials for the all-party meeting are available here: http://www.cpuc.ca.gov/General.aspx?id=6442451195.

[119] Alternatively, the IOUs could seek permission to procure on their own initiative in a manner consistent with the Commission's Rules of Practice and Procedure or in a subsequent RPS Plan.

relative to its request not to hold a 2018 solicitation is reasonable. Should PG&E determine that an RPS solicitation or bilateral contracts are needed during the time period covered by the 2018 solicitation cycle, or prior to the Commission issuing a decision on the 2019 RPS Procurement Plans, PG&E is directed to first seek Commission permission in a manner consistent with the Commission's Rules of Practice and Procedure. The authorization granted in this decision solely exempts PG&E from the annual solicitation requirement for the year of 2019.

We find that PG&E's framework to assess whether to hold or sell excess RPS volumes is reasonable. PG&E is authorized to conduct solicitations for the sales of RPS volumes if the pro forma sales agreement for any such sale is executed during the timeframe covered by its 2018 RPS Procurement Plan, or prior to the Commission issuing a decision on the 2019 RPS Procurement Plans. Solicitations must comply with all relevant Commission decisions, including D.11-12-052, which prohibits the transfer of Portfolio Content Category 1 and 2 RECs generated prior to the effective date of the contract. For the IOUs, the effective date of the contract is the date that Commission approval of the contract is final. PG&E may also engage in bilateral sales transactions that do not utilize the pro forma sales agreement submitted with its 2018 RPS Procurement Plan or that are not executed after PG&E receives bids for a sales solicitation resulting from its 2018 RPS Procurement Plan, subject to the Commission's review and approval of completed transactions.

PG&E must seek the Commission's approval through an advice letter for any significant modification to any procurement contract for RPS-eligible resources that was approved by the Commission.

11.2. SCE's 2018 RPS Procurement Plan

We find that SCE's 2018 RPS Plan satisfies the specific requirements for the 2018 RPS Procurement Plans that were set forth in the *2018 ACR*, and that SCE's evaluation of its current RPS procurement needs relative to its request not to hold a 2018 solicitation is reasonable. Should SCE determine that an RPS solicitation or bilateral contracts are needed during the time period covered by the 2018 solicitation cycle, or prior to the Commission issuing a decision on the 2019 RPS Procurement Plans, SCE is directed to first seek Commission permission in a manner consistent with the Commission's Rules of Practice and Procedure. The authorization granted in this decision solely exempts SCE from the annual solicitation requirement for the year of 2018.

We find that SCE's framework to assess whether to hold or sell excess RPS volumes is reasonable. SCE is authorized to conduct solicitations for the sales of RPS volumes if the pro forma sales agreement for any such sale is executed during the timeframe covered by its 2018 RPS Procurement Plan, or prior to the Commission issuing a decision on the 2019 RPS Procurement Plans. Solicitations must comply with all relevant Commission decisions, including D.11-12-052, which prohibits the transfer of Portfolio Content Category 1 and 2 RECs generated prior to the effective date of the contract. For the IOUs, the effective date of the contract is the date that Commission approval of the contract is final. SCE must s seek Commission approval of short-term sales resulting from a solicitation or any bilateral transaction that both utilizes the pro forma sales agreement submitted with its 2018 RPS Procurement Plan and is executed after SCE receives bids for a sales solicitation resulting from its 2018 RPS Procurement Plan. SCE may also engage in bilateral sales transactions that do not utilize the pro forma sales agreement submitted with its 2017 RPS Procurement Plan or that are not executed after SCE receives bids for a sales solicitation resulting from its 2018 RPS Procurement Plan, subject to the Commission's review and approval.

SCE must seek the Commission's approval through an advice letter for any significant modification to any procurement contract for RPS-eligible resources that was approved by the Commission.

Lastly, we find that SCE's description of the treatment of Workforce Development and Disadvantaged Communities in its Least-Cost, Best-Fit methodology lacks sufficient detail. SCE shall include more information on the treatment of Workforce Development and Disadvantaged Communities in its Final RPS Procurement Plan.

11.3. SDG&E's 2018 RPS Procurement Plan

We find that SDG&E's 2018 RPS Procurement Plan satisfies the specific requirement for 2018 RPS Procurement Plans that were set forth in the *2018 ACR*, and that SDG&E's evaluation of its current RPS procurement needs relative to its request not to hold a 2018 solicitation is reasonable. Should SDG&E determine that an RPS solicitation or bilateral contracts are needed during the time period covered by the 2018 solicitation cycle, or prior to the Commission issuing a decision on the 2019 RPS Procurement Plans, SDG&E is directed to first seek Commission permission in a manner consistent with the Commission's Rules of Practice and Procedure. The authorization granted in this decision solely exempts SDG&E from the annual solicitation requirement for the year of 2018.

We find that SDG&E's framework to assess whether to hold or sell excess RPS volumes is reasonable. SDG&E is authorized to conduct solicitations for the sales of RPS volumes if the pro forma sales agreement for any such sale is executed during the timeframe covered by its 2018 RPS Procurement Plan, or prior to the Commission issuing a decision on the 2019 RPS Procurement Plans.

Solicitations must comply with all relevant Commission decisions, including D.11-12-052, which prohibits the transfer of Portfolio Content Category 1 and 2 RECs generated prior to the effective date of the contract. For the IOUs, the effective date of the contract is the date that Commission approval of the contract is final. SDG&E may also engage in bilateral sales transactions that do not utilize the pro forma sales agreement submitted with its 2018 RPS Procurement Plan or that are not executed after SDG&E receives bids for a sales solicitation resulting from its 2018 RPS Procurement Plan, subject to the Commission's review and approval.

SDG&E must seek the Commission's approval through an advice letter for any significant modification to any procurement contract for RPS-eligible resources that was approved by the Commission.

11.4. Time of Delivery Factors

In its Draft RPS Plan, PG&E proposes to eliminate TOD factors from its RPS procurement contract and Least Cost Best Fit (LCBF) valuations. SCE's Draft RPS Plan includes use of TOD factors, but SCE presents arguments why it would like the Commission to authorize eliminating TOD factors. SDG&E's Draft RPS Plan includes TOD factors, which it has described as being updated to reflect evolving market conditions.

11.4.1. Background

TOD factors are a set of multipliers used to adjust contract payments based on set hours of the day (TOD periods) and the expected time-differentiated cost of electricity. TOD periods vary seasonally and consist of multi-hour blocks of time. As an example, SCE has six TOD periods a year: on-peak, off-peak, and super-off-peak for both summer and winter.[120]

TOD factors have been used in two different ways in the RPS program. First, IOUs use TOD factors in their LCBF valuations to forecast a bid's total contract cost, by adjusting expected contract payments according to the time and quantity of energy deliveries provided in a bid. Second, the IOUs use TOD factors to calculate actual contract payments for procured renewable generation over the term of a contract.[121] TOD factors are not used to value energy benefits of a bid in LCBF;[122] they are only used to calculate contract cost.[123]

11.4.2. Discussion

In order to resolve the proposals to eliminate TOD factors, we consider the comments received in response to the Administrative Law Judge's Ruling of September 12, 2018 *Requesting Comments on Staff Proposal on Effective Load Carrying Capability, Time of Delivery Factors, and Project Viability*. The Energy Division Staff proposal suggested that IOUs could use TOD factors in one of the following three ways: (1) for informational purposes only; (2) for valuing bids with LCBF and calculating actual contract payments; or (3) for LCBF valuations

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[120] SCE, *2017 Final Renewables Portfolio Standard Procurement Plan: Appendix G.1* at 150 (January 17, 2018, R.15-02-020).

[121] If a PPA includes time of delivery (TOD) factors, the periods and factors are fixed over the course of the contract.

[122] Energy benefits are based on the unique hourly values of energy for every year in the procurement horizon and energy cost forecasts.

[123] PG&E, *Reply Comments on Energy Division Staff Paper on Least-Cost Best-Fit Reform for Renewables Portfolio Standard Procurement* at 14 (August 8, 2016, R.15-02-020); See SDG&E, *Final 2017 Renewables Portfolio Standard Procurement Plan: Appendix 9* at p. 3 (January 17, 2018, R.15-02-020); SCE, Final *2017 Renewables Portfolio Standard Procurement Plan: Appendix H.1* at 4 (January 17, 2018, R.15-02-020).

only. Several parties supported Energy Division Staff's TOD proposal, asserting that the first option allows the IOUs to decouple TOD factors from contract payments.[124] Parties argued the adoption of information-only TOD factors will allow the IOUs to better communicate preferences for energy deliverers over the course of the procurement horizon to developers.

GPI, California Energy Storage Alliance (CESA), and Small Business Utility Advocates (SBUA) opposed Staff's proposal for information-only TOD factors and elimination of TOD factors in contract payments.[125] These parties all seek more detailed TOD factors applied to valuations and contract payments. GPI states that if the link between TOD factors and contract payments is broken, developers will not be properly incentivized to deliver energy at the right times.[126] Also, GPI recommended having TOD factors that refresh on year ten for twenty-year contracts.[127]

SCE, PG&E, SDG&E, Cal WEA, Calpine, and Cal PA support Staff's proposal for informational-only TOD factors.[128] SCE asserts that developers will

124 PG&E, *Opening Comments to Staff's 2018 LCBF Proposal* at 12; SCE, *Opening Comments to Staff's 2018 LCBF Proposal* at 11; SDG&E, *Opening Comments to Staff's 2018 LCBF Proposal* at 6-7; Cal WEA, *Opening Comments to Staff's 2018 LCBF Proposal* at 8; Calpine, *Opening Comments to Staff's 2018 LCBF Proposal* at 6; Cal PA, *Opening Comments to Staff's 2018 LCBF Proposal* at 7.

125 GPI, *Opening Comments to Staff's 2018 LCBF Proposal* at 6-8; CESA, *Opening Comments to Staff's 2018 LCBF Proposal* at 11-13; SBUA, *Opening Comments to Staff's 2018 LCBF Proposal* at 10-11; *see also* Jan Reid, *Comments to 2018 Draft RPS Procurement Plans* at 7-9; CESA, *Comments to 2018 Draft RPS Procurement Plans* at 6-7.

126 GPI *Opening Comments to Staff's 2018 LCBF Proposal* at 6-8; GPI *Reply Comments to Staff's 2018 LCBF Proposal.*

127 GPI *Reply Comments to Staff's 2018 LCBF Proposal* at 1-2.

128 PG&E, *Opening Comments to Staff's 2018 LCBF Proposal* at p. 12; SCE, *Opening Comments to Staff's 2018 LCBF Proposal* at 11; SDG&E, *Opening Comments to Staff's 2018 LCBF Proposal* at 6-7;

Footnote continued on next page

still be incentivized to bid and build projects that deliver energy when the system needs it, even if information-only TOD factors are adopted, because LCBF bid valuations consider the time-differentiated value of energy as a benefit.[129] Moreover, Calpine asserted that developers merely modify their pre-TOD-adjusted contract costs to realize the post-TOD-adjusted contract costs they need, indicating that TODs do not provide an energy delivery incentive to generators.[130] Lastly, Cal PA opposes TOD refreshes as this approach creates payment uncertainty which negatively impacts project financing.[131]

PG&E and SCE also discuss reasons to eliminate TOD factors in future contracts in Sections 7.8.1 and 8.8.2, above.

Based on the above discussion, the Commission accepts the staff proposal's first option—use of TOD factors for informational purposes. The first option enables IOUs 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. Additionally, we agree with SCE's comments that incentives to submit competitive offers for energy deliveries to meet system needs will not be eliminated with the adoption of this TOD option.

The Commission also accepts the staff proposal's second option—TOD factors for use in LCBF valuations and calculating contract payments. The retention of the historic dual uses of TOD factors was supported by several

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Cal WEA, *Opening Comments to Staff's 2018 LCBF Proposal* at 8; Calpine, *Opening Comments to Staff's 2018 LCBF Proposal* at 6; Cal PA, *Opening Comments to Staff's 2018 LCBF Proposal* at 7.

[129] SCE, *Opening Comments to Staff's 2018 LCBF Proposal* at 13.

[130] Calpine, *Opening Comments to Staff's 2018 LCBF Proposal* at 5-6.

[131] Cal PA, *Reply Comments to Staff's 2018 LCBF Proposal* at 7.

parties and its application may be needed in the future.[132] Scenarios where the second option may remain useful include solicitations with co-located RPS generation and storage as well as unforeseen situations where the first option may not be a good fit.

The Commission does not accept the staff proposal's third TOD option—TOD factors for the sole use of valuing projects and not applying them to executed contracts' pricing in contracts. If TOD factors are not used to calculate the contract payments for actual generation, they should not be used to value projects because this valuation framework would incorrectly assume TOD-adjustments are going to occur when they are not.[133] However, the Commission will allow under option two for LCBF project valuations to occur with TOD adjustments, but through contract negotiations remove TOD-adjustments from contract payments.

In summary, the Commission adopts Staff's proposal with modification. In this decision, we direct that the IOUs use one of the two following options:

- TOD factors for informational purposes only, or
- TOD factors for valuing bids with LCBF and calculating actual contract payments.

IOUs shall make appropriate revisions in Final 2018 RPS Procurement Plans to reflect this directive.

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[132] GPI, *Opening Comments to Staff's 2018 LCBF Proposal* at pp. 6-8; SBUA, *Opening Comments to Staff's 2018 LCBF Proposal* at 10-11; Jan Reid, *Comment to Draft 2018 RPS Procurement Plans* at 7-9; CESA, *Opening Comments to Staff's 2018 LCBF Proposal* at pp. 11-13; CESA, *Opening Comments to Draft 2018 Procurement Plans* at 6-7.

[133] *See* SCE, *Opening Comments to Staff's 2018 LCBF Proposal* at 13.

Moreover, the Commission agrees with parties that there should be a stakeholder process for the development of information-only TOD factor requirements.[134] To initiate the process the Commission directs the IOUs to develop joint or separate information-only TOD factors proposal(s). The proposal(s) should incorporate several recommendations from parties to provide enough information and granularity such that the TOD factors do convey useful information to potential bidders. These recommendations include: "a matrix of factors that would change over the long-term contract horizon;"[135] factors consistent with the month-hour matrix framework used in an Arizona Public Service request for proposals;[136] and "forecasted energy values, finely differentiated across locations, seasons, days and hours," that indicate periods with expected curtailment.[137] The IOUs' proposal(s) shall be served on the R.18-07-003 service list within 90 days of the issuance of this decision in its final form. Further, stakeholders shall have 20 days to provide opening comment on the proposal(s) and 10 days from opening comments deadline to provide reply comments.

12. Small and Multi-Jurisdictional Utilities (SMJU)

The small and multi-jurisdictional utilities are Bear Valley, PacifiCorp, and Liberty Utilities (CalPeco). Pursuant to the 2018 ACR, these utilities were

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[134] Cal WEA, *Opening Comments to Staff's 2018 LCBF Proposal* at p. 9; Cal PA, *Opening Comments to Staff's 2018 LCBF Proposal* at 8; *see* CESA, *Opening Comments to Staff's 2018 LCBF Proposal* at 14.

[135] SCE, *Opening Comments to Staff's 2018 LCBF Proposal* at 13-14.

[136] CESA, *Opening Comments to Staff's 2018 LCBF Proposal* at p. 14; Arizona Public Service Company, *2018 Peaking Capacity Request for Proposals* at15, 28 (April 26, 2018).

[137] Cal WEA, *Opening Comments to Staff's 2018 LCBF Proposal* at 9.

required to, and in fact did, submit RPS procurement plans that provided the information required in Sections 5.1-5.8, and 5.10-5.13 of the 2018 ACR.

Bear Valley and PacifiCorp RPS procurement plans are approved without modification.

Liberty Utilities has primarily been procuring through an agreement with NV Energy to meet its RPS requirements. More recently Liberty Utilities' utility owned 50 MW Luning Solar Project achieved commercial operation and it expects its other utility owned project, Turquoise Solar project, to achieve commercial operation. This procurement to date has been approved via the Commission's application process.[138] To meet future RPS requirements, Liberty Utility requests that the Commission provide it authority to undertake short-term procurement and one or more competitive solicitations for utility-owned California RPS-eligible resources.[139] Liberty CalPeco provided additional details of this planned procurement in the Integrated Resource Planning proceeding (R.16-02-007).[140] In reviewing RPS contracts submitted to the Commission for review and approval, the Commission reviews for consistency with approved RPS procurement plans.[141] To ensure that Liberty Utilities' RPS procurement could be found reasonable and costs recoverable in rates, Liberty Utilities shall update its draft 2018 RPS Plan to specify that it will

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[138] Approved in D15-12-021, D.16-01-021 and D.17-12-008.

[139] Updated 2018 Renewables Portfolio Standard Procurement Plan of Liberty Utilities (CalPeco Electric) LLC, at 8.

[140] Liberty Utilities (CalPeco Electric) LLC (U-933-E) Response to ALJ Ruling Requesting Additional Information (November 9, 2018).

[141] Pub. Util. Code § 399.13(d).

seek Commission approval of any authorized procurement via the processes approved in D.14-11-042, D.03-06-071, D.09-06-050 and Pub. Util. Code § 399.14.

13. Community Choice Aggregators (CCA)

The CCAs are identified in the Summary section of this decision. Pursuant to the *2018 ACR*, these companies were required to, and in fact did, submit RPS procurement plans that provided the information required in Sections 5.1-5.6 and 5.8, and 5.11-5.13 of the *2018 ACR*. None provided the additional cost information requested in Section 5.10.

As several parties noted,[142] many of the CCAs' 2018 RPS Procurement Plans were scant on information. The RPS plans mandated by Pub. Util. Code § 399.13(a)(1) must be more than a list of factors to consider during procurement. They must explain how the LSE plans to reach its Net RPS Procurement Need. Specifically, in the RNS Calculations LSEs submit to the Commission, CCAs should address whether they will hold a solicitation this year, how many MWs they intend to procure this year, how many MWs they intend to procure long term, the resources they intend to procure in particular portfolio content categories, their Net RPS Procurement Need (variable E in the RNS calculation table), the steps planned to reach it, what appropriate minimum margin of procurement and information on upcoming participation in solicitations or other forms of procurement that are needed.

14. Energy Service Providers (ESP)

The ESPs are identified in the Summary section of this decision. Pursuant to the *2018 ACR*, these companies were required to, and in fact did, submit RPS

[142] *Comments* submitted on September 21, 2018 from American Wind Energy Association Caucus (ACC), GPI, IEPA, and LSA.

Procurement Plans that provided the information required in Sections 5.1-5.6, 5.8, and 5.11-5.13 of the *2018 ACR*. None provided the additional cost information requested in Section 5.10.

As several parties noted,[143] many of the ESPs' 2018 RPS Procurement Plans were scant on information. The RPS Procurement Plans mandated in Pub. Util. Code 399.13(a)(1) must be more than a list of factors to consider during procurement and must explain how the LSE plans to reach their Net RPS Procurement Need. Specifically, in the RNS Calculations LSEs submit to the Commission, ESPs should state whether they will hold a solicitation this year, how many MWs they intend to procure this year, how many MWs they intend to procure long term, the resources they intend to procure in particular portfolio content categories, address their Net RPS Procurement Need (variable E in the RNS calculation table), the steps planned to reach it, the appropriate minimum margin of procurement and information on upcoming participation in solicitations or other forms of procurement that are needed to reach compliance.

15. Procurement from Biomass Facilities Using High Hazard Zone Fuel or Feedstock

We find that PG&E's, SCE's, and SDG&E's requests not to hold a 2018 solicitation are reasonable, and that PG&E, SCE, and SDG&E may enter into bilateral contracts to facilitate any potential contracts with existing forest bioenergy facilities receiving feedstock from high hazard zones pursuant to SB 901 (stats. 2018, ch. 626), which amends Pub. Util. Code § 399.20.3 during the duration of the 2018 RPS solicitation cycle. PG&E, SCE, and SDG&E shall

[143] *Id*.

modify their 2018 RPS Procurement Plans to reflect this authorization. SMJUs, CCAs, and ESPs should also consider any similar changes to their 2018 Plans.

16. Categorization and Need for Hearing

This proposed decision confirms the categorization of this proceeding as ratesetting. This proposed decision modifies the earlier determination that hearings were needed.

17. Comments on Proposed Decision

The proposed decision of ALJs Mason and Atamturk in this matter was mailed to the parties in accordance with Pub. Util. Code § 3ll.

On February 11, 20919, we received opening comments from California Energy Storage Alliance, California Wind Energy Association and Large-Scale Solar Association, Joint Community Choice Aggregators, Independent Energy Producers, Joint Investor-Owned Utilities, Liberty Utilities, Public Advocates Office, Jan Reid, and Shell Energy.

On February 19, 2019, reply comments were served by Alliance for Retail Energy Markets, American Wind Energy Association, CCA Parties, Green Power Institute, and the Joint IOUs.

Summary of Comments

California Energy generally supports the decision but makes two suggestions: first, that the Commission engage in further consideration of the merits of Option 2 as the default use of TOD factors in the future in this proceeding; and second, that the Commission continue to develop the ELCC methodology for hybrid RPS resources that include co-located energy storage resources.

California Wind and Large-Scale Solar Alliance argue that the decision to be revised to direct CCA's and ESP to revise their RPS Plans to correct the deficiencies noted in the decision, rather than allow the CCAs and ESPs to provide more granular information in their next cycle.

Independent Energy Producers questions the retail sellers' intent to procure approximately 1,319 MW of new, incremental RPS-eligible capacity over the 10-year planning horizon. Independent Energy is concerned that such procurement will be short of the forecast for new, incremental RPS-eligible resources to meet RPS mandates and GHG-reduction goals. As such Independent Energy Producers recommends that Commission should reject the retail sellers' 2018 RPS Procurement Plans, and to direct an increase in the RPS Minimum Procurement Quantity imposed on all jurisdictional retail sellers such that 2,000-3,000 MWs of incremental, new RPS-eligible resources are procured in the 2019-2020 timeframe.

The Joint IOUs raise a concern regarding perceived inconsistencies between themselves and the retail sellers. They claim that the retail sellers' RPS plans are being approved even though the decision finds the retail sellers' plans to be deficient. In contrast the Joint IOUs claim that their RPS Procurement Plans must be modified when the Commission finds them not in compliance with Commission directives. The Joint IOUs ask the Commission to treat the Joint IOUs and the retail sellers consistently. In addition, the Joint IOUs seek clarifications regarding TOD factors to provide flexibility in developing information-only TOD proposals; clarifications regarding their ability to make modifications to pro forma RPS sales agreements; clarifications regarding the applicable regulatory process for seeking Commission approval for various RPS contract amendments; inclusion of a reference to PG&E's December 21, 2018 Motion to Update; confirmation that the Joint IOUs do not need to seek additional advance approval from the Commission to establish reserve prices in the sales solicitations order for Tree Mortality-related contracts; and identification of minor inconsistencies and errors in the decision.

The Joint CCA parties disagree with the decision's determination that their RPS Procurement Plans lack factual specificity. Nevertheless, the Joint CCA parties also acknowledge that the RPS Procurement Plans vary in detail because man of the CCAs have only recently begin providing service to customers. As such, not all CCAs will be able to precisely identify all planned long-term procurement during their initial years of operation.

Liberty Utilities request that the decision be revised to explicitly authorize it to utilize similar expedited processes to seek approval of certain RPS contracts. Liberty Utilities ask for this change on the grounds that while the decisions reference prior decisions that Liberty Utilities may utilize, these prior decisions only provided authorizations the Joint IOUs.

California Public Advocates ask that the decision should be modified to require SDG&E to detail its REC sales methodology through Tier 1 or Tier 3 advices letters, or in an update to its 2018 RPS Plan. California Public Advocates ask that the decision should be modified to require SCE to either file a Tier 1 advice letter or motion within 30 days of a final decision if SCE seeks to update its REC sales strategies.

Jan Reid asks that the decision be revised in five respects: order PG&E to update their plan using the CEC's transportation electricity demand forecast; order PG&E to update its plan to indicate that it will use the Project Viability Calculator in its contract assessment process; order PG&E to update is RPS Plan to assume a volumetric project failure rate equal to PG&E's average volumetric project failure rate for the 2012-2017 period; reject PG&E's proposal to continue to sign index contracts for RPS resources; and prohibit PG&E from establishing an escalation rate for RPS contracts.

Shell Energy asks that the Commission coordinate LSEs' reporting obligations in the RPS proceeding and the IRP proceeding before imposing an additional reporting obligation.

Discussion

The Commission indicates below what portions of the decision that it has revised. Since some of the parties' comments have overlapped by subject matter, the discussion section is organized by subject topic rather than by party. To the extent a party's comments are not addressed in this discussion section, it is because the Commission rejects those comments.

SCE Proposed Sales Solicitation

Since Commission staff and the parties can review updated strategy in the final RPS Procurement Plans, we do not believe that it is necessary for SCE to file a Tier 1 advice letter. But as we agree that additional direction could be given regarding the inclusion of information, page 58 and Conclusion of Law (COL) 9 are revised as follows:

> Page 58: Thus, it is reasonable for SCE to update its sales strategies, if necessary, to reflect increase in RPS position forecasts that do not include GAM or PAM, in its final 2018 RPS Procurement Plan as a result of D.18-10-019.
>
> COL 9: It is reasonable for SCE to update its sales strategies in its final 2018 RPS Plan as a result of D.18-10-019 to reflect increase in RPS position forecasts that do not include GAM or PAM assumptions.

ESP Plans: We agree to include a deadline for ESPs to file their RPS Plans and add the following to Ordering Paragraph (OP) 3:

> <u>Effective 35 days from this decision's issuance, any new ESPs must file their RPS Plans upon registering with the Commission or 90 days prior to delivering load, whichever event occurs first.</u>

<u>Liberty Procurement Authorization:</u> We correct OP 5 so it is consistent with the text on page 101 of the decision. OP 5 now reads as follows:

> Liberty shall seek Commission approval of any authorized procurement via the same processes approved <u>in D.03-06-071, D.09-06-050,</u> D.14-11-042, and Pub. Util. Code § 399.14.

<u>PG&E RPS Plan:</u> We agree with Jan Reid's assertion that PG&E's removal of the Project Viability Calculator form its least-cost, best-fit methodology is inconsistent with D.09-06-018. As such, we will add the following OP after OP 11:

> <u>Pacific Gas and Electric Company shall update its Least Cost Best Fit Methodology to include the Project Viability Calculator in its final RPS Procurement Plan.</u>

<u>Sales Authorization and Agreements:</u> We agree with the Joint IOUs' proposed clarifications regarding sales authorization and agreements. OPs 8, 9, and 10 have been revised to reflect those clarifications.

<u>BioRAM Changes:</u> We deny the IOUs' proposed modifications to FOF #3, COL #2, OP #8, OP #9, OP #10, and OP #12 related to the BioRAM nonbypassable charge decision because these modifications seek to inappropriately modify the BioRAM Non-bypassable Charge decision (D.18-12-003). The IOUs' modification would allow them to procure renewables from their own BioRAM sales. D.18-12-003 requires the IOUs to sell a portfolio content category 1 BioRAM product that includes both the energy and the REC. The BioRAM NBC decision further states that if an IOU is not able to sell the product that the REC will not count toward the RPS requirements of any load serving entity. D.18-12-003 is clear in its direction that the IOU must *sell* the

BioRAM bundled product to determine its value or to count its value as $0 if it cannot be sold.

We also deny the IOUs' proposed modifications to set a reservation price for the bundled BioRAM energy as this would also inappropriately modify D.18-12-003.

<u>COL Modification:</u> Conclusion of Law 1 is modified as follows:

> Each utility seller <u>IOU, CCA, and ESP</u> remains responsible for meeting its RPS Program procurement requirements implemented in D.16-12-040.

<u>Modification in Text:</u> A sentence on page 7 is modified as follows:

> PG&E also completed its RAM procurement, which resulted in a total of 1,604 MW of approved contracts <u>for all IOUs</u>.

<u>SCE Update to RPS Plan:</u> We deny the Joint IOUs' request to modify OP 10 related to SCE modifying its proposed RPS sales to reflect the proposed modifications made by PG&E in its 12/21 Motion to Update. Specifically, the Joint IOUs comment that SCE will seek to also seek to limit its REC sales to 2 years or less, until the Commission issues a PCIA Phase 2. The Commission has been clear that if an IOU would like to update its RPS Procurement Plans, it may do so through a motion.

18. Assignment of Proceeding

Clifford Rechtschaffen is the assigned Commissioner and Robert M. Mason III and Nilgun Atamturk are the co-assigned ALJs in this proceeding.

Findings of Fact

1. PG&E's, SCE's, and SDG&E's 2018 RPS Procurement Plans do not seek authorization for renewable procurement in excess of SB 100's 60% RPS target.
2. PG&E, SCE, and SDG&E forecast exceeding RPS requirements through at least the 2017-2020 compliance period.

3. PG&E, SCE, and SDG&E do not request to hold RPS solicitations to purchase RPS volumes for the period covered by the 2018 RPS Procurement Plans, or until the Commission issues a decision on the 2019 RPS Procurement Plans.

4. PG&E, SCE, and SDG&E seek authorization to conduct sales solicitations for RPS volumes during the period covered by the 2018 RPS Procurement Plans.

5. All ESPs required to file RPS Procurement Plans in 2018 complied and provided information required under Sections 5.1-5.6, 5.8, and 5.11-5.13 of the *June 21, 2018 ACR*. None of the ESPs submitted additional cost information as requested in Section 5.10 of the ACR.

6. All CCAs required to file RPS Procurement Plans in 2018 complied and provided information required under Sections 5.1-5.6, 5.8, and 5.11-5.13 of the *2018 ACR*. None of the CCAs submitted additional cost information as requested in Section 5.10 of the ACR.

7. Bear Valley Electric Service and Liberty Utilities, LLC submitted RPS Procurement Plans providing the information required in Sections 5.1-5.8 and 5.10-5.13 of the 2018 *ACR*.

8. PacifiCorp submitted an IRP providing the information required under Sections 5.1-5.8 and 5.10-5.13 of the 2018 *ACR*.

9. It is reasonable for SCE to update its sales strategies in its final 2018 RPS Plan as a result of D.18-10-019 to reflect increase in RPS position forecasts that do not include GAM or PAM assumptions.

10. It is reasonable for SCE to update its LCBF Methodology to include how workforce development and disadvantaged communities is considered in offer evaluations.

11. Palmco Power CA, is an ESP that does not serve any retail load.

Conclusions of Law

1. Each IOU, CCA, and ESP remains responsible for meeting its RPS Program procurement requirements implemented in D.16-12-040.

2. Based on PG&E's, SCE's, and SDG&E's current stated RPS compliance positions, it is reasonable to approve of PG&E's, SCE's, and SDG&E's requests not to hold 2018 RPS solicitations.

3. Due to their long RPS positions through the current 2017-2020 compliance period, it is reasonable to authorize PG&E, SCE, and SDG&E to engage in sales of RPS volumes for the period covered by the 2018 RPS Procurement Plans.

4. It is reasonable to require PG&E and SCE to follow the TOD options for use in LCBF valuations and for calculating contract payments, or just for informational purposes.

5. For the fair and transparent development of the RPS program, a public stakeholder process is needed for the establishment of information-only TOD factors requirements.

6. The IOUs may use the updated TOD factors in other RPS procurement programs subject to Commission approval through a Tier 1 Advice Letter process.

7. To ensure that Liberty Utilities' RPS procurement could be found reasonable and costs recoverable in rates, Liberty Utilities should update its draft 2018 RPS Procurement Plan to include the required process for Commission review and approval of RPS procurement contracts.

8. As first established in D.13-11-024, it is reasonable to not require one ESP, Palmco Power CA, to file an RPS Procurement Plan because it does not serve retail load. It is not reasonable to exempt registered ESPs from the requirement to file RPS Compliance Reports.

9. It is reasonable to require that PG&E, SCE, and SDG&E seek Commission approval through an advice letter for any significant modification to any procurement contract for RPS-eligible resources that was approved by the Commission.

10. All motions for confidential treatment are consistent with Commission decisions and should be granted.

O R D E R

IT IS ORDERED that:

1. Pursuant to the authority provided in Public Utilities Code Section 399.13(a)(1), the draft 2018 Renewables Portfolio Standard Procurement Plans, including the related Solicitation Protocols, filed by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are accepted.

2. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company (IOUs) shall file Final 2018 Renewables Portfolio Standard (RPS) Procurement Plans, modified in accordance with this decision, with the Commission within 30 days of the issuance date of this decision. The IOUs may issue solicitations to sell RPS volumes 7 days after filing Final 2018 RPS Procurement Plans unless the IOU's amended RPS Procurement Plan is suspended by the Energy Division Director within the 7-day period.

3. Pursuant to Public Utilities Code Section 365.1(c)(1), the 2018 Renewables Portfolio Standard Procurement Plans filed by the following electric service providers (ESP) are accepted and deemed final: 3 Phases Renewables, Agera Energy, LLC, American PowerNet Management, LP, Calpine PowerAmerica-CA,

LLC, Calpine Energy Solutions, LLC, Commerce Energy of Montana, Inc. (dba Commercial Energy of California), Constellation NewEnergy, Inc., Direct Energy Business LLC, Direct Energy Services, LLC, EDF Industrial Power Services (CA), LLC, EnerCal USA, LLC (dba Yep Energy, Y.E.P.), Just Energy Solutions, Inc., Liberty Power Holdings, LLC, Pilot Power Group, Inc., Shell Energy North America (US), L.P., The Regents of the University of California, and Tiger Natural Gas, Inc. Effective 35 days from this decision's issuance, any new ESPs must file their RPS Plans upon registering with the Commission, or 90 days prior to delivering load, whichever event occurs first.

4. Pursuant to Public Utilities Code Section 365.1(c)(1), the 2017 Renewables Portfolio Standard (RPS) Procurement Plans filed by the following community choice aggregators (CCA) are accepted and deemed final: Redwood Coast Energy Authority, Apple Valley Choice Energy, Marin Clean Energy, Pico Rivera Innovative Municipal Energy, Silicon Valley Clean Energy, Sonoma Clean Power Authority, Peninsula Clean Energy, CleanPowerSF, Lancaster Choice Energy, San Jacinto Power, Monterey Bay Community Power, Valley Clean Energy, Rancho Mirage Energy Authority, Clean Power Alliance of Southern California, East Bay Community Energy, Pioneer Community Energy, San Jose Community Energy, Solana Energy Alliance, Desert Community Energy, and King City. Effective 35 days from this decision's issuance, any other new CCAs must file their RPS plans upon registering with the Commission or 90 days prior to delivering load, whichever event occurs first.

5. Liberty Utilities (CalPeco) (Liberty) is authorized to hold a 2018 Renewables Portfolio Standard (RPS) solicitation and shall indicate in its Final 2018 RPS Procurement Plans additional details regarding the planned procurement to be filed pursuant to the schedule adopted herein. Liberty shall

seek Commission approval of any authorized procurement via the processes approved in D.03-06-071, D.09-06-050, D.14-11-042, and Public Utilities Code Section 399.14.

6. Liberty Utilities (CalPeco) shall file a Final 2018 Renewables Portfolio Standard (RPS) Procurement Plan, modified in accordance with this decision, with the Commission within 30 days of the issuance date of this decision.

7. The 2018 Renewables Portfolio Standard Procurement Plans of Bear Valley Electric Service and PacifiCorp are accepted and deemed final.

8. San Diego Gas & Electric Company (SDG&E) is authorized to not hold a 2018 Renewables Portfolio Standard (RPS) solicitation and shall indicate in its Final 2018 RPS Procurement Plan to be filed pursuant to the schedule adopted herein that it will seek permission from the Commission to procure any amounts, other than amounts separately mandated by the Commission (*i.e.*, Feed-In Tariff during the time period covered by the 2018 solicitation cycle.) This authorization to not hold a solicitation only applies to the 2018 RPS solicitation cycle. SDG&E is authorized to conduct solicitations for the short-term sales of 5 years or less, of sales of RPS volumes if the sales agreement for any such sale is executed during the period after the Commission's adoption of this decision and prior to adoption of a subsequent RPS Plan. Deliveries under any such short-term sales agreement, including any agreement with a delivery term of 5 years or less, may commence at any time after the Commission's approval of the contract and continue until the expiration of the contract's term. SDG&E must seek Commission approval of short-term sales resulting from a solicitation or any bilateral transaction that both utilizes the pro forma sales agreement submitted with its 2018 RPS Procurement Plan, showing any necessary modifications, and is executed after SDG&E receives bids for a sales solicitation resulting from its

2018 RPS Procurement Plan consistent with Decision (D.) 14-11-042's rules for expedited approval of short-term contracts, and D.09-06-050's rules regarding bilateral contracts. SDG&E may also engage in bilateral sales transactions that do not utilize the pro forma sales agreement submitted with its 2018 RPS Procurement Plan or that are not executed after SDG&E receives bids for a sales solicitation resulting from its 2018 RPS Procurement Plan, subject to the Commission's review and approval. SDG&E shall file a final 2018 RPS Procurement Plan with any updated solicitation materials.

9. Pacific Gas and Electric Company is authorized to not hold a 2018 Renewables Portfolio Standard (RPS) solicitation and shall indicate in its Final 2018 RPS Procurement Plans to be filed pursuant to the schedule adopted herein that it will seek permission from the Commission to procure any amounts, other than amounts separately mandated by the Commission (*i.e.*, Feed-In Tariff and Renewable Auction Mechanism, during the time period covered by the 2018 solicitation cycle.) This authorization to not hold a solicitation only applies to the 2018 RPS solicitation cycle. PG&E is authorized to conduct solicitations for short-term sales of 5 years or less, of sales of RPS volumes if the sales agreement for any such sale is executed during the period after the Commission's adoption of this decision and prior to adoption of a subsequent RPS Plan. Deliveries may commence at any time after the Commission's approval of the contract, and continue until the expiration of the contract's term. PG&E must seek Commission approval of short-term and long-term sales resulting from a solicitation or any bilateral transaction that both utilizes the pro forma sales agreement submitted with its 2018 RPS Procurement Plan, showing any necessary modifications, and is executed after PG&E receives bids for a sales solicitation resulting from its 2018 RPS Procurement Plan consistent with

Decision (D.) 14-11-042's rules for expedited approval of short-term contracts and D.09-06-050's rules regarding bilateral contracts. PG&E may also engage in bilateral sales transactions that do not utilize the pro forma sales agreement submitted with its 2018 RPS Procurement Plan or that are not executed after PG&E receives bids for a sales solicitation resulting from its 2018 RPS Procurement Plan, subject to the Commission's review and approval as established in D.09-06-050. PG&E shall file a final 2018 RPS Procurement Plan with any updated solicitation materials.

10. Southern California Edison (SCE) is authorized to not hold a 2018 Renewables Portfolio Standard (RPS) solicitation and shall indicate in its Final 2018 RPS Procurement Plan to be filed pursuant to the schedule adopted herein that it will seek permission from the Commission to procure any amounts, other than amounts separately mandated by the Commission (*i.e.*, Feed-In Tariff and Renewable Auction Mechanism, during the time period covered by the 2018 solicitation cycle.) This authorization to not hold a solicitation only applies to the 2018 RPS solicitation cycle. SCE is authorized to conduct solicitations for the short-term sales of 5 years or less, of sales of RPS volumes if the sales agreement for any such sale is executed during the period after the Commission's adoption of this decision and prior to the adoption of a subsequent RPS Plan. Deliveries under any such short-term sales agreement, including any agreement with a delivery term of 5 years or less, may commence at any time after the Commission's approval of the contract and continue until the expiration of the contract's term. SCE must seek Commission approval of short-term sales resulting from a solicitation or any bilateral transaction that both utilizes the pro forma sales agreement submitted with its 2018 RPS Procurement Plan, showing any necessary modifications, and is executed after SCE receives bids for

a sales solicitation resulting from its 2018 RPS Procurement Plan consistent with Decision (D.) 14-11-042's rules for expedited approval for short-term contracts and D.09-06-050's rules regarding bilateral contracts. SCE may also engage in bilateral sales transactions that do not utilize the pro forma sales agreement submitted with its 2018 RPS Procurement Plan or that are not executed after SCE receives bids for a sales solicitation resulting from its 2018 RPS Procurement Plan, subject to the Commission's review and approval of completed transactions, as established in D.09-06-050. SCE shall file a final 2018 RPS Procurement Plan with any updated solicitation materials.

11. Southern California Edison shall update its Least Cost Best Fit Methodology to explain how workforce development and disadvantaged communities is considered in offer evaluations.

12. Pacific Gas and Electric Company shall update its Least Cost Best Fit Methodology to include the Project Viability Calculator in its final RPS Procurement Plan.

13. In the event Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), or San Diego Gas & Electric Company (SDG&E) decides to hold a 2018 Renewables Portfolio Standard solicitation or execute bilateral contracts, PG&E, SCE, or SCE shall first seek permission from this Commission in a manner consistent with the Commission's Rules of Practice and Procedure.

14. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall continue to incorporate and describe how expected economic curtailment affects their Renewables Portfolio Standard (RPS) procurement in future RPS procurement plans.

15. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall modify their 2018 RPS procurement plans to reflect authorized procurement pursuant to Senate Bill 901 (stats. 2018, ch. 626) from existing forest bioenergy facilities receiving feedstock from high hazard zones, during the duration of the 2018 RPS solicitation cycle.

16. Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company shall utilize one of the following two Time of Delivery options: for use in Least Cost Best Fit valuations and calculating contract payments; or just for informational purposes.

17. Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company shall develop joint or separate information-only Time of Delivery (TOD) factors proposal(s), that are more granular TOD factors than the historic TOD factors and change over the long-term contract horizon. The proposals shall be mailed to the service list of this proceeding within 90 days of the issuance of this decision in its final form.

18. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall seek the Commission's approval through an advice letter for any significant modification to any procurement contract for renewable portfolio standard-eligible resources that was approved by the Commission.

19. For 2019, community choice aggregators and electric service providers shall include more granular information regarding planning in the next annual procurement plan cycle in 2019, beyond a general statement that they will comply with the Renewables Portfolio Standard requirements and upcoming long-term procurement requirements.

20. All motions for confidentiality as to the 2018 Renewables Portfolio Standard Plans are granted.

21. All motions to update the 2018 Renewables Portfolio Standard Procurement Plan are granted.

22. The Motion for Provisional Waiver from Future RPS Compliance Reports is granted in favor of Palmco Power CA, as it applies to the Renewables Portfolio Standard (RPS) procurement plans. The requirement to file annual RPS compliance reports remains unchanged.

23. Rulemaking 18-07-003 remains open.

This order is effective today.

Dated February 21, 2019, at San Francisco, California.

MICHAEL PICKER
President
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
Commissioners

Appendix A

2018 RPS Plans
Acronym List

Acronym	Term
2018 RPS Plan	2018 Renewables Portfolio Standard Procurement Plan
AAEE	Additional Achievable Energy Efficiency
AAPV	Additional Achievable Photovoltaics
AB	Assembly Bill
ACR	*Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review of 2018 Renewables Portfolio Standard Procurement Plans* issued June 21, 2018
ADNU	Area Delivery Network Upgrades
ADS	Automated Dispatch System
AL	Advice Letter
ALJ	Administrative Law Judge
API	Application Programming Interface
ASC	Accounting Standards Codification
AVCE	Apple Valley Choice Energy
BioMAT	Bioenergy Market Adjusting Tariff
BioRAM	Bioenergy Renewable Auction Mechanism
BNI	Binding Notice of Intent
CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
CARB	California Air Resources Board
CBA	California Balancing Authority (SDG&E); California Balancing Authority Area (SCE)
CCA	Community Choice Aggregators/Aggregation

CEC	California Energy Commission
CED	California Energy Demand
CEQA	California Environmental Quality Act
COD	Commercial Operation Date
CP	Compliance Period
CPA	Clean Power Alliance
CPCN	Certificate of Public Convenience and Necessity
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CR	Community Renewables
D.	Decision
DA	Direct Access
DAC	Disadvantaged Communities
DBE	Diverse Business Enterprise
DCE	Desert Communities Energy
DER	Distributed Energy Resource
DERP	Distributed Energy Resource Provider
DG	Distributed Generation
DLAP	Default Load Aggregation Point
DNA	Delivery Network Upgrades
ECO	East County
ECR	Enhanced Community Renewables
EE	Energy Efficiency
EJ	Environmental Justice
ELCC	Effective Load Carrying Capacity

EPC	Engineering, Procurement, and Construction
ERR	Eligible Renewable Resource
ERRA	Energy Resource Recovery Account
ESP	Electric Service Provider
EV	Electric Vehicle
FCDS	Full Capacity Deliverability Status
FERC	Federal Energy Regulatory Commission
FFO	Funds From Operations
FIT	Feed-In Tariff
GAM	Green Allocation Mechanism
GCOD	Guaranteed Commercial Operation Date
GHG	Greenhouse Gas
GIS	Geographic Information System
GO	General Order
GRC	General Rate Case
GT	Green Tariff
GTSR	Green Tariff Shared Renewables Program
GWh	Gigawatt-hour
HVDC	High Voltage Direct Current
ID&WA	Irrigation District and Water Agency
IE	Independent Evaluator
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
IOU	Investor-Owned Utility

IPP	Independent Power Producer
IR	Interconnection Request
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
IV	Imperial Valley
kWh	Kilowatt-hour
LCBF	Least-Cost Best-Fit
LCE	Lancaster Choice Energy
LCR	Local Capacity Requirement
LDNU	Local Delivery Network Upgrades
LOLP	Loss of Load Probability
LSE	Load-Serving Entity
LTPP	Long-Term Procurement Plan
MW	Megawatt
MWh	Megawatt-hour
NBC	Non-Bypassable Charge
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NMV	Net Market Value
NP15 Hub	North of Path 15 Hub
NPV	Net Present Value
NQC	Net Qualifying Capacity
NU	Network Upgrades
OIR	Order Instituting Rulemaking

OP	Ordering Paragraph
OSHA	Occupational Safety and Health Administration
PAV	Portfolio Adjusted Value
PCC	Portfolio Content Categories
PCIA	Power Charge Indifference Adjustment
PD	Proposed Decision
PEL	Procurement Expenditure Limitation
PFM	Petition for Modification
PG&E	Pacific Gas and Electric Company
PPA	Power Purchase Agreement
PPTA	Power Purchase Tolling Agreement
PQR	Procurement Quantity Requirement
PRG	Procurement Review Group
PRIME	Pico Rivera Innovative Municipal Energy
PRP	Preferred Resources Pilot
PTC	Production Tax Credit
PTO	Participating Transmission Owner
PURPA	Federal Public Utility Regulatory Policies Act of 1978
PV	Photovoltaic
PV RAM	Photovoltaic Renewable Auction Mechanism
QF	Qualifying Facility
R.	Rulemaking
RA	Resource Adequacy
RAM	Renewable Auction Mechanism
REC	Renewable Energy Credit

ReMAT	Renewable Market Adjusting Tariff
RFO	Request for Offers
RFP	Request for Proposal
RICA	Renewable Integration Cost Adder
RMEA	Rancho Mirage Energy Authority
RNS	Renewable Net Short
RNS Ruling	*Administrative Law Judge's Ruling on Renewable Net Short* issued May 21, 2014
RPS	Renewables Portfolio Standard
RPS Guidebook	CEC's RPS Renewables Portfolio Standard Eligibility Commission Guidebook
RTM	Real-Time Markets
S&P	Standard and Poor's
SB	Senate Bill
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SJP	San Jacinto Power
SONGS	San Onofre Nuclear Generating Station
SONS	Stochastically-Optimized Net Short
SPVP	Solar Photovoltaic Program
SWPL	Southwest Powerlink
TE	Transportation Electrification
TOD	Time Of Delivery/Day
TOU	Time of Use
TPD	Transmission Plan Deliverability
TPP	Transmission Planning Process

TRTP	Tehachapi Renewable Transmission Project
TURN	The Utility Reform Network
TWRA	Tehachapi Wind Resource Area
UOG	Utility-Owned Generation
VIE	Variable Interest Entities
VMOP	Voluntary Margin of Procurement (PG&E); Voluntary Margin of Over-Procurement (SDG&E and SCE)
WECC	Western Electric Coordinating Council
WREGIS	Western Renewable Energy Generation Information System

(End of Appendix A)