Decision 14-11-042 November 20, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	Rulemaking 11-05-005 (Filed May 5, 2011)

DECISION CONDITIONALLY ACCEPTING 2014 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS AND AN OFF-YEAR SUPPLEMENT TO 2013 INTEGRATED RESOURCE PLAN

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DECISION CONDITIONALLY ACCEPTING 2014 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS AND AN OFF-YEAR SUPPLEMENT TO 2013 INTEGRATED RESOURCE PLAN

1. Summary

Pursuant to the authority provided in Public Utilities Code Section 399.13(a)(1),[1] today's decision conditionally accepts, as modified herein, the draft 2014 Renewables Portfolio Standard (RPS) Procurement Plans, 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). We further accept SDG&E's request not to hold a 2014 RPS solicitation based on its progress in meeting the statutory RPS compliance period requirements.

We direct PG&E, SCE and SDG&E to file final 2014 RPS Procurement Plans pursuant to the 2014 RPS solicitation schedule adopted herein. PG&E and SCE are directed to initiate the RPS solicitation process for 2014 within 14 days of the mailing date of this decision pursuant to the 2014 RPS solicitation schedule adopted herein.

In this decision, we address the significant modifications, as compared to last year's plans, in the 2014 RPS Procurement Plans filed by PG&E, SCE, and SDG&E. We accept or reject these modifications below.

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[1] Section 399.13(a)(1) provides, in full, as follows: "The commission shall direct each electrical corporation to annually prepare a renewable energy procurement plan that includes the matter in paragraph (5), to satisfy its obligations under the renewables portfolio standard. To the extent feasible, this procurement plan shall be proposed, reviewed, and adopted by the commission as part of, and pursuant to, a general procurement plan process. The commission shall require each electrical corporation to review and update its renewable energy procurement plan as it determines to be necessary." All subsequent code section references are to the Public Utilities Code unless otherwise indicated.

Today's decision also accepts PacifiCorp's July 15, 2014 Off-Year Supplement to its 2013 Integrated Resource Plan filed and deems it final. No further filings are required.

This decision accepts the RPS Procurement Plans filed by two smaller utilities, Bear Valley Electric Service, a Division of Golden State Water Company, and Liberty Utilities LLC (CalPeco Electric).

Pursuant to § 365.1(c)(1)[2] and Decision (D.) 11-01-026, this decision accepts the RPS Procurement Plans filed by electric service providers (ESPs).[3] We deem the filings of the ESPs and the two smaller utilities as final 2014 RPS Procurement Plans. No further filings are required, except for Direct Energy Business, LLC.

This decision also adopts certain aspects of the Energy Division's April 8, 2014 proposal to reform parts of the RPS procurement review process. Our adopted reforms reflect the Commission's efforts to streamline the RPS contract review process and increase the transparency. The reforms include additional data adequacy requirements and definitive timeline for seeking Commission approval of RPS contracts.

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2 Section 365.1 was enacted by Senate Bill (SB) 695 (Kehoe, Stats. 2009, ch. 337) and provides, among other things, for the phased and limited reopening of direct access transactions in the service territories of the three large utilities. The statute also requires that, once the Commission has begun the process of reopening direct access, the Commission shall equalize certain program requirements between the three large utilities and "other providers," including electric service providers. Section 365.1 exempts community choice aggregators from this requirement.

3 Section 365.1 and D.11-01-026, *Decision Revising Rules for the Renewables Portfolio Standard Pursuant to Senate Bill 695* (January 13, 2011). In D.11-01-026, the Commission found that almost all significant RPS requirements currently apply equally to large utilities and ESPs. The decision adds to the RPS obligations of ESPs, such as the filing of RPS Procurement Plans for Commission acceptance. D.11-01-026 at 28 (Ordering Paragraph 1).

This decision addresses the Commission's Renewable Auction Mechanism (RAM), the RPS procurement program created by the Commission in D.10-12-048. As part of our review, we adopt one additional RAM auction, RAM 6, under a structure similar to past RAM auctions. Beyond RAM 6, we adopt a revised RAM process at reflects the current renewable procurement market for smaller projects. As part of the review of RAM, we address issues raised by PG&E's February 26, 2014 Petition for Modification of RAM.[4]

This proceeding does not address aspects of the RPS Program set forth in Assembly Bill (AB) 327 (Perea, Stats. 2013, ch. 611). The Commission will address AB 327 early next year.

This proceeding remains open.

2. Procedural History

This rulemaking was initiated, among other things, to implement Senate Bill (SB) 2 of the 2011-2012 First Extraordinary Session (Simitian, Stats. 2011, ch. 1) (SB 2 1X) and for the continued administration of the California Renewables Portfolio Standard Program (RPS Program).

The RPS Program was established by SB 1078, effective January 1, 2003 (Sher, Stats. 2002, ch. 516).[5] This legislation stated, among other things, that the amount of electricity procured per year from eligible renewable energy resources, as defined therein, would be an amount equal to at least 20% of the total electricity sold to retail customers in the state by December 31, 2017. The

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[4] In a separate proceeding, Application 09-02-019, the proceeding involving PG&E's Solar Photovoltaic (Solar PV) Program, we also consider a related Petition for Modification filed by PG&E on February 26, 2014 to close its PV program and move any remaining capacity to RAM.

[5] The RPS statute is codified at §§ 399.11-399.32.

Legislature modified and accelerated this goal to 20% by 2010 in SB 107 (Simitian, Stats. 2006, ch. 464). In 2011, SB 2 1X made several changes to the RPS Program, most notably extending the RPS goals from 20% of retail sales of California's investor-owned utilities (utilities or IOUs), electric service providers (ESPs), and community choice aggregators (CCAs) by the end of 2010 to 33% of retail sales of utilities, ESPs, CCA, and publicly owned utilities by 2020.[6] SB 2 1X also modified or changed many details of the RPS Program, including creating Portfolio Content Categories[7] for RPS procurement and establishing specific Compliance Periods for measuring compliance with the 33% goals.[8]

Effective January 1, 2014, Assembly Bill (AB) 327 (Perea, Stats. 2013, ch. 611) further amended the RPS statutes. This legislation, among other things, provides the Commission with the authority to establish a higher procurement target for retail sellers beyond the existing 33% target. The Commission anticipates addressing its authority to increase the procurement target beyond 33% under AB 327 in a new rulemaking to be initiated in early 2015. Therefore, we make no specific findings regarding AB 327 in this decision.

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6 SB 2 1X was enacted by the Legislature in 2011 in the 2011-2012 First Extraordinary Session effective on December 10, 2011.

7 Portfolio Content Categories for the RPS Program are set forth in § 399.16 and were added to the statute by SB 2 1X in 2011. The Commission defined and implemented these code provisions in Decision (D.) 11-12-052, *Decision Implementing Portfolio Content Categories for the Renewables Portfolio Standard Program* (December 15, 2011). D.11-12-052 sets forth the criteria required for generation from eligible-renewable resources to be counted as Category 1, Category 2, or Category 3 under § 399.16(b)(1)-(3).

8 D.11-12-020 *Establishes Procurement Quantity Requirements for Retail Sellers* sets the procurement quantity requirements, referred to as Compliance Periods 1, 3 and 3 for the RPS Program.

The most recent Scoping Memo was issued in this proceeding on January 13, 2014.[9] All the issues addressed herein fall within the scope of this proceeding as defined in the January 13, 2014 Scoping Memo.

2.1. 2014 RPS Procurement Plans

On March 26, 2014, the assigned Commissioner initiated the 2014 procurement portion of this proceeding by issuing the *Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2014 Renewables Portfolio Standard Procurement Plans* (March 26, 2014 ACR).

The March 26, 2014 ACR directed utilities and ESPs to file RPS Procurement Plans for 2014. In accordance with the March 26, 2014 ACR, utilities and ESPs filed their draft 2014 RPS Procurement Plans in June 2014 describing the actions that would be undertaken to meet their RPS Program procurement requirements. These plans include many aspects, such as compliance with General Order 156 and § 8283, as amended by AB 1386.[10]

Section 8283 is the statutory provision requiring utilities to submit plans for "increasing procurement from women, minority, and disabled veteran business enterprises in all categories, including, but not limited to, renewable energy…." Two Commissioners addressed the application of § 8283 to the RPS Procurement Plans in a concurrence filed with D.12-11-016, stating "[b]ecause of the importance of California's RPS, it must be inclusive of California's dynamic and ever-evolving demographics, and the entities that bid into the RPS

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[9] January 13, 2014 *Third Amended Scoping Memo and Ruling of Assigned Commissioner* (January 13, 2014); *see also*, September 12, 2012, *Amended Scoping Memo and Ruling of the Assigned Commissioner*.

[10] AB 1386 (Bradford, Stats. 2011, ch. 443).

solicitations should not be exempted from the core value of diversity in utility procurement."[11] We affirm this statement today.

On August 20, 2014, utilities and ESPs were provided with the opportunity to file updates to their previously filed draft 2014 Plans. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) filed updates.

The smaller utilities filed 2014 draft RPS Procurement Plans, including Bear Valley Electric Service, a Division of Golden State Water Company, and Liberty Utilities LLC (CalPeco Electric). These smaller utilities are subject to a subset of the filing requirements set forth in the March 26, 2014 ACR.[12] PacificCorp, the only multi-jurisdictional utility, is permitted by statute to file an Integrated Resource Plan (IRP) which is prepared for regulatory agencies in other states provided that the IRP complies with the requirements under California law.[13] PacifiCorp filed this document on April 30, 2013 and its 2013 IRP update on March 31, 2014. More recently PacifiCorp filed an Off-Year Supplement on July 15, 2014.

The following ESPs filed 2014 RPS Procurement Plans:[14] 3 Phases Renewables, LLC, Calpine PowerAmerica-CA, LLC's, Commerce Energy, Inc., Commercial Energy of California, Constellation NewEnergy, Inc., Direct Energy Business, LLC (DEB), Direct Energy Services, LLC, EDF Industrial Power Services, LLC, Gexa Energy California, LLC, Glacial Energy of California, Inc.,

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11 D.12-11-016, *Decision Conditionally Accepting 2012 Renewables Portfolio Standard Procurement Plans* (November 8, 2012) at 97, *Concurrence of Commissioners Peevey and Simon.*

12 March 26, 2014 ACR at 7-9; § 399.18(a)(5) and § 399.18(b).

13 Section 399.17(d) and D.08-05-029, as modified by D.09-11-014, *RPS Participation on Participation of Small and Multi-Jurisdictional Utilities in Renewables Portfolio Standard Program*.

14 March 26, 2014 ACR at 7-9.

Liberty Power Holdings, LLC, Noble Americas Energy Solutions LLC, Palmco Power CA, LLC, Pilot Power Group, Inc., Shell Energy North America (US), L.P., Southern California Telephone & Energy, Tenaska California Energy Marketing, LLC, Tenaska Power Services Company, The Regents of the University of California, Tiger Natural Gas, Inc., and Yep Energy.

The major modifications of the RPS Procurement Plans filed by PG&E, SCE, and San Diego Gas & Electric Company (SDG&E) are addressed in today's decision.

2.2. Energy Division Proposals in March 26, 2014 ACR

The March 26, 2014 ACR also presented several Energy Division proposals for revising the RPS procurement planning and review process. The proposal presented in the ACR included a: (1) capacity valuation, (2) project development requirements, and (3) renewable integration adder. Parties submitted comments on these proposals on July 2, 2014 and July 30, 2014. We address these issues below.

2.3. Renewable Net Short

For the 2012 and 2013 RPS Procurement Plans, the Administrative Law Judge (ALJ) requested the use of the Energy Division's proposal regarding the renewable net short (RNS) methodology[15] set forth in rulings dated July 11, 2012[16] and May 10, 2013,[17] respectively. For the 2014 RPS Procurement Plans, the

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15 RNS refers to the amount of new renewable generation necessary for retail sellers to meet or exceed the renewable procurement quantity requirements.

16 The ALJ issued a ruling on August 2, 2012 to enter the Energy Division's final RNS methodology into the record and directed the use of that methodology in the August 15, 2012 updates to the 2012 RPS Procurement Plans.

ALJ issued a ruling on May 21, 2014 with a revised RNS to reflect changes recommended by the Energy Division, after receipt of comments. The May 21, 2014 ruling requested the utilities and ESPs to use the revised RNS methodology for calculating the RNS for purposes of their 2014 RPS Procurement Plans.[18] Furthermore, we affirm the statement in the May 21, 2014 ruling that a future ruling will address the application of the proposed Energy Division's risk adjustment methodology.[19]

2.4. December 31, 2014 Energy Division Analysis and April 8, 2014 Energy Division Proposal

Recently, parties have addressed issues raised in a December 31, 2013 analysis by the Energy Division on the function of the Commission's Renewable Auction Mechanism (RAM) within the RPS market and an April 8, 2014 proposal by the Energy Division on reforming the existing RPS procurement review process. RAM was addressed in an analysis attached to the December 31, 2013, *Energy Division Summary and Questions on Future of RAM*, and procurement reform was addressed in an Energy Division proposal dated April 8, 2014, *April 2014 RPS Procurement Reform Staff Proposal*. Parties filed comments on both. We address these below.

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17 *Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2013 Renewable Portfolio Standard Procurement Plans Pursuant to Public Utilities Code Sections 399.11 et seq. and Requesting Comments on a New Proposal* at 7 (May 10, 2013).

18 May 21, 2014, *Administrative Law Judge's Ruling on Renewable Net Short*.

19 May 21, 2014, *Administrative Law Judge's Ruling on Renewable Net Short*, Section 4.4 (Energy Division's proposed risk adjustment methodology) at 3-4.

3. Overview of 2014 RPS Procurement Plan Requirements

The 2014 draft RPS Procurement Plans filed by PG&E, SCE, and SDG&E include a number of components.[20] The Public Utilities Code requires that specific matters be addressed in an electric corporation's RPS procurement plan, including: (1) assessment of RPS portfolio supply and demand; (2) potential compliance delays; (3) project status update; (4) risk assessment; (5) quantitative information; (6) bid solicitation protocol, (7) cost quantification.[21] The Commission has established additional requirements and the March 26, 2014 ACR requested specific information for 2014.

PG&E and SCE filed updates to their June 4, 2014 RPS Procurement Plans on August 20, 2014. SDG&E did not file an update.

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[20] For example, SCE's August 20, 2014 Amended Draft 2014 RPS Procurement Plans includes (1) Redline of 2014 Written Plan at Appendix A; (2) Project Development Status Update at Appendix B; (3) Physical Renewable Net Short Calculation Based on California Public Utilities Commission (CPUC) Assumptions & Physical Renewable Net Short Calculation Based on SCE Assumptions at Appendices C.1 and C.2; (4) Optimized Renewable Net Short Calculations Based on CPUC Assumptions & Optimized Renewable Net Short Calculations Based on SCE Assumptions at Appendices C.3 and C.4; (5) Cost Quantification Table at Appendix D; (6) RECs From Expiring Contracts at Appendix E; (7) 2014 Procurement Protocol & Redline of 2014 Procurement Protocol at Appendices F.1 and F.2; (8) 2014 Pro Forma Renewable Power Purchase and Sale Agreement & Redline of 2014 Pro Forma Renewable Power Purchase and Sale Agreement at Appendices G.1 and G.2; (9) Pro Forma Master Renewable Energy Credit Purchase Agreement at Appendix H; (10) SCE's Least-Cost Best-Fit Methodology at Appendix I.1 & Redline of SCE's Least-Cost Best Fit Methodology at Appendix I.2; (11) 2014 Form of Seller's Proposal at Appendix J.1 & Redline of 2014 Form of Seller's Proposal at Appendix J.2. PG&E and SDG&E's 2014 Draft RPS Procurement Plans include substantially similar documents. Some of these documents have been designated confidential. All of these documents, to the extent that they are not confidential, are available at the link referred to as the *Docket Card* on the Commission's website.

[21] Section 399.13(a)(5)(A)-(F); D.04-07-029 (setting forth LCBF methodology); SB 836 (Padilla, Stats. 2011, ch. 600, § 1) which imposes new RPS data quantification reports to the legislature.

3.1. PG&E

Generally, PG&E states the following regarding compliance with RPS statutorily mandated procurement requirements:[22] Based on preliminary results presented in PG&E's March 2014 Compliance Report, PG&E delivered approximately 22.5% of its power from renewable sources in 2013, ending the first Compliance Period (2011-2013) with a slight surplus relative to its multi-year compliance requirement.[23] PG&E projects it will meet its second Compliance Period RPS requirements of 25%.[24] Before applying excess procurement from the first and second Compliance Periods, PG&E anticipates a small RPS open position for the third (2017-2020) Compliance Period.[25]

3.2. SCE

In SCE's 2014 RPS Procurement Plan, SCE states the following regarding compliance with RPS statutorily mandated procurement requirements: SCE served approximately 21.6% of its retail sales from RPS-eligible resources in 2013, ending the first Compliance Period (2011-2013) at an average of 20.7%. SCE projects a net long RPS position for Compliance Period (2014-2016) and a net

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[22] PG&E November 10, 2014 comments at 4-6, PG&E requests to postpone its annual RPS Procurement solicitation based on a revised forecast of its Renewable Net Short filed in a different proceeding. This revised forecast is currently under consideration by the Commission and parties. PG&E suggests that if its actual sales turn out to be similar to its new projection, without any changes in generation projections from existing or contracted projects, then PG&E Renewable Net Short would be significantly different than it originally projected in its 2014 Draft RPS Procurement Plan.

[23] PG&E August 20, 2014 updated RPS Procurement Plan at 20.

[24] PG&E August 20, 2014 updated RPS Procurement Plan at 20.

[25] PG&E August 20, 2014 updated RPS Procurement Plan at 20.

short RPS position for Compliance Period (2017-2020). SCE also forecasts a net short RPS position for 2021 and beyond.

3.3. SDG&E

In its 2014 RPS Procurement Plan, SDG&E explains that for the first Compliance Period (2011-2013), SDG&E has met its obligations and it is waiting for confirmation from the Commission.[26] Regarding the second Compliance Period (2014-2016), SDG&E states it expects it will meet its RPS goals with generation from executed contracts and deliveries from utility-owned generation.[27] Regarding the third Compliance Period (2017-2020), based on current probability-weighted RPS position forecast, SDG&E states that it may not require additional procurement and will continue to monitor a multitude of factors to assess its future needs.[28] In further explaining its approach to meeting the RPS goals of Compliance Period 2017-2020, SDG&E states that the level of new purchases required will be a function of portfolio performance and will be subject to the level of banking, if any, related to potential excess procurement in Compliance Period 2014-2016 into Compliance Period 2017-2020.[29]

4. General Issues Related to 2014 RPS Procurement Plans

To the extent the 2014 RPS Procurement Plans filed by PG&E, SCE, and SDG&E include significant modification to their plans filed in 2013, we address these issues below. Although SDG&E will not hold a 2014 RPS solicitation, we

[26] SDG&E June 6, 2014 Draft RPS Procurement Plan at 16.

[27] SDG&E June 6, 2014 Draft RPS Procurement Plan at 16.

[28] SDG&E June 6, 2014 Draft RPS Procurement Plan at 16.

[29] SDG&E June 6, 2014 Draft RPS Procurement Plan at 16.

review revised materials submitted by SDG&E in an effort to maintain those materials as current as possible. We address general matters below in Section 4. We address matters specific to the pro forma contracts and solicitation materials in Section 5.

4.1. Safety Considerations

The Commission in D.13-11-024 directed all retail sellers filing RPS Procurement Plans to incorporate a section on safety considerations regarding the procurement of electricity.[30] The Commission directive was made pursuant to its authority under § 451, which provides, in pertinent part, as follows:

> Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities, …, as necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public.

The March 26, 2014 ACR reiterated the directive in D.13-11-024.[31]

Today, we find the 2014 draft RPS Procurement Plans acceptable in terms of the information provided on safety considerations. Safety considerations are an ongoing requirement to be addressed in all future RPS Procurement Plans.[32]

4.2. Assembly Bill 327 – Beyond the 33% Target

In today's decision, we clarify our intention to issue a new rulemaking in early 2015 to address the authority provided to the Commission pursuant to

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30 D.13-11-024, *Decision Conditionally Accepting 2013 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan and On-Year Supplement* (November 20, 2013), Ordering Paragraph 3 at 69.

31 March 26, 2014 ACR at 19.

32 D.13-11-024, *Decision Conditionally Accepting 2013 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan and On-Year Supplement*, Ordering Paragraph 3 at 69.

AB 327 to modify the statutory RPS targets beyond 33%. AB 327, effective January 1, 2014, amended § 399.15(b) as follows, showing in underline (additions) and in strikeout (deletions), are:

> (b)(2)(A) No later than January 1, 2012, the commission shall establish the quantity of electricity products from eligible renewable energy resources to be procured by the retail seller for each compliance period. These quantities shall be established in the same manner for all retail sellers and result in the same percentages used to establish compliance period quantities for all retail sellers.
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> (B) In establishing quantities for the compliance period from January 1, 2011, to December 31, 2013, inclusive, the commission shall require procurement for each retail seller equal to an average of 20% of retail sales. For the following compliance periods, the quantities shall reflect reasonable progress in each of the intervening years sufficient to ensure that the procurement of electricity products from eligible renewable energy resources achieves 25% of retail sales by December 31, 2016, and 33 % of retail sales by December 31, 2020. The commission shall require retail sellers to procure not less than 33 percent of retail sales of electricity products from eligible renewable energy resources in all subsequent years.
>
> (C) Retail sellers shall be obligated to procure no less than the quantities associated with all intervening years by the end of each compliance period. Retail sellers shall not be required to demonstrate a specific quantity of procurement for any individual intervening year.
>
> (3) The commission ~~shall not~~ may require the procurement of eligible renewable energy resources in excess of the quantities identified in paragraph (2). ~~A retail seller may voluntarily increase its procurement of eligible renewable energy resources beyond the renewables portfolio standard procurement requirements.~~

Several parties state that the IOUs' 2014 RPS Plans should either consider or seek authorization for renewable procurement in excess of the current RPS

Program's 33% requirement, referring to AB 327 to support this request.[33] In response, PG&E and SDG&E state that the Commission must first implement AB 327 and that, currently, the IOUs' do not operate under a directive to procure amounts beyond 33% under the RPS program.[34] The IOUs do have the authority to request the permission of the Commission to procure amounts beyond the requirements set forth in the statute.[35]

The Commission must first implement AB 327. Only then will the IOUs need to act in compliance with any new directive the Commission adopts consistent with AB 327. All matters related to procurement beyond 33% under the RPS Program will be reviewed in great detail in the rulemaking anticipated by early 2015. The arguments by CEERT, CUE, Iberdrola, IEP and LSA are rejected now and maybe resubmitted, to the extent relevant, in the new proceeding anticipated in early 2015.

4.3. Imperial Valley - Monitoring and Sunrise Powerlink Transmission Project & Least-Cost, Best-Fit Update

In this decision, we require continued monitoring of the utilities' procurement activities in the Imperial Valley area and renewable projects' use of the Sunrise Powerlink Transmission project. In addition, we authorize the utilities to use the California Independent System Operator's (CAISO's) *Advisory*

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[33] Center for Energy Efficiency and Renewable Technologies (CEERT) July 2, 2014 comments at 4-17; Coalition of California Utility Employees (CUE) July 2, 2014 comments at 3; Iberdrola Renewables, LLC (Iberdrola) July 2, 2014 comments at 2; IEP (Independent Energy Producers Association) July 2, 2014 comments at 2; LSA (Large-Scale Solar Association) July 2, 2014 comments at 2-3.

[34] SDG&E July 30, 2014 comments at 4; PG&E July 30, 2014 comments at 19-20.

[35] Section 399.13 and PG&E July 30, 2014 comments at 20.

Estimates of Future Resource Adequacy Import Capability for valuing resource adequacy benefits in the least-cost, best-fit (LCBF) evaluation of offers.

On December 18, 2008, the Commission adopted D.08-12-058,[36] which approved the 500-kilovolt Sunrise Powerlink Transmission Project.[37] We have previously addressed issues related to the Sunrise Powerlink Transmission Project in prior RPS Procurement Plan decisions, and we again address related issues. Specifically, in D.09-06-018, the Commission directed monitoring of proposals and projects in the Imperial Valley area to ensure that the Sunrise Powerlink is used efficiently, equitably, and wisely.[38] Additionally, in D.12-11-016, the Commission confirmed a previous directive set forth in a June 7, 2011 Assigned Commissioner Ruling (June 7, 2011 ACR) which directed the utilities to assume a maximum import capability of 1,400 megawatts (MW) from the Imperial Irrigation District (IID) Balancing Authority Area when calculation capacity benefits in their LCBF evaluations of offers.[39]

In its 2014 RPS Procurement Plan, SDG&E reports that it currently has 15 contracts in the Imperial Valley/IID territory that are forecasted to provide 3,753 gigawatt-hours (GWh) per year.[40] Further, SDG&E states that as of

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[36] D.08-12-058, *Decision Granting a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project (*December 18, 2008).

[37] The 117 mile Sunrise Powerlink Transmission Project runs from Imperial County to San Diego and was energized on June 18, 2012.

[38] D.09-06-018, *Decision Conditionally Accepting 2009 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan Supplements* (June 8, 2009).

[39] D.12-11-016 *Decision Conditionally Accepting 2012 Renewables Portfolio Standard Procurement Plans* (November 8, 2012) and *Assigned Commissioner's Ruling Regarding Resource Adequacy Value of RPS Projects in the Imperial Valley Irrigation District Balancing Authority Area* (June 7, 2011).

[40] SDG&E's June 6, 2014 Draft RPS Procurement Plan at 51.

May 2014, four of the projects have reached commercial operation and generation from those projects is expected to be approximately 1,800 GWh per year.[41] Additionally, PG&E has one executed contract with a project located in the Imperial Valley area and SCE reports that as a result of its 2013 RPS solicitation that it has executed contracts with two projects located in the Imperial Valley area.[42]

In adopting the 1,400 MW import capability assumption, the Commission acknowledged it was a regulatory tool to support the development of cost-effective renewable resources that could be enabled by the Sunrise Powerlink. The IOUs have calculated capacity benefits in their LCBF evaluation of offers as directed. In its draft 2014 RPS Procurement Plan, however, SCE proposes to use the CAISO's 10-year forecast of expected import capability[43] for calculating the capacity benefit portion of an offer's LCBF evaluation, instead of the assumed 1,400 MW of import capability.[44]

SCE asserts that the modification to its LCBF methodology is reasonable because CAISO has established a new process for determining forward-looking estimates of maximum import capability instead of its previous methodology that calculated import capabilities based on historical energy imports.[45] SCE

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[41] SDG&E's June 6, 2014 Draft RPS Procurement Plan at 51.

[42] PG&E Advice Letter 4363-E and SCE's August 20, 2014 Amended Draft RPS Procurement Plan at 42.

[43] CAISO's Advisory Estimates of Future Resource Adequacy Import Capability (July 11, 2013) http://www.caiso.com/Documents/AdvisoryEstimates-FutureResourceAdequacyImportCapability_Years2013-2022.pdf.

[44] SCE's August 20, 2014 Amended Draft RPS Procurement Plan at 60.

[45] SCE's August 20, 2014 Amended Draft RPS Procurement Plan at 60.

asserts that the previous concerns of CAISO's methodology attributing zero import capability from IID no longer exist because the methodology at the time of the Commission's directive in June 7, 2011 ACR and D.12-11-016 no longer exist.[46]

CEERT objects to SCE's proposal to modify how it will value capacity benefits of IID projects asserting that the change may undercut the value of the resources.[47]

While the Commission is encouraged by the execution of contracts in the Imperial Valley area and successful development of new renewable energy facilities, we continue to direct monitoring of renewable procurement activities in the Imperial Valley area. Only a small portion of the executed contracts are operational, and continued monitoring will enable the Commission and the public to observe the progress of renewable facilities development in the area.

The Commission directed the IOUs to assume a maximum import capacity from the IID Balancing Area, in part, to recognize the resource potential in the Imperial Valley area. While the Commission still recognizes the Imperial Valley resource potential, the Commission agrees with SCE that it is reasonable to calculate capacity benefits for offers located in the Imperial Valley area based on CAISO's *Advisory Estimates of Future Resource Adequacy Import Capability* because CAISO's methodology for calculating maximum import capability has changed. This change in CAISO's methodology eliminates the Commission's previous concerns. Further, the Commission finds it reasonable for PG&E and SDG&E to calculate its resource adequacy benefits based on the same CAISO estimates.

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[46] SCE July 30, 2014 comments at 14.

[47] CEERT July 2, 2014 comments at 20.

Therefore, SCE's proposal to modify its least-cost, best-fit methodology by calculating resource adequacy benefits based on CAISO's *Advisory Estimates of Future Resource Adequacy Import Capability* is approved. Furthermore, the Commission's requirement to assume a maximum import capability of 1,400 MW from IID Balancing Authority Area as directed in June 7, 2011 ACR and D.12-11-016 is removed.

Accordingly, the Commission's Energy Division staff shall continue to monitor RPS development in the Imperial Valley according to the parameters set forth in Appendix A of D.09-06-018. Consistent with D.12-11-016, PG&E, SCE, and SDG&E shall provide a specific assessment of the offers and contracted projects in the Imperial Valley region in future RPS Procurement Plans filed with the Commission pursuant to §§ 399.11 *et seq*. until directed otherwise.

In its final 2014 RPS Procurement Plan, SCE's least-cost, best-fit methodology that calculates resource adequacy benefits based on CAISO's *Advisory Estimates of Future Resource Adequacy Import Capability* is approved. Furthermore, in their final RPS Procurement Plan, PG&E and SDG&E shall, as applicable, remove the assumption of a maximum import capability of 1,400 MW from IID Balancing Authority Area adopted in the June 7, 2011 ACR and D.12-11-016 and may base its resource adequacy calculations on CAISO's *Advisory Estimates of Future Resource Adequacy Import Capability*.

5. Modifications to the RPS Bid Solicitation Protocols and Pro Form Contracts

Pursuant to § 399.13(a)(5)(C) and in response to the March 26, 2014 ACR, PG&E, SCE, and SDG&E submitted solicitation protocols and pro forma contracts as part of their draft 2014 RPS Procurement Plans.[48] These solicitation protocols and pro forma contracts included, among other things, the following information: solicitation goals, bid eligibility requirements, terms for participating in the solicitations, descriptions of the solicitation process, descriptions of LCBF bid evaluation methodologies, and pro forma agreements.

The bid solicitation protocols seek to provide specific information on the parameters of the forthcoming RPS solicitation. More specifically, the bid solicitation protocols state the utilities' procurement goals for the solicitation and desired deliverability characteristics of the resources it intends to procure, such as, online date and locational preferences, and other statutory or Commission-mandated requirements.

In contrast to the 2013 bid solicitation protocols, the 2014 bid solicitation materials include several new protocols, including reducing the minimum size for project eligibility and revisions to Time-of-Delivery (TOD) factors. The utilities also submit modifications their pro forma contracts. We address the following modifications: whether utilities should have the right to review and either accept or reject project design changes, tax incentive provisions, whether project developers must exclusively negotiate with one IOU, contract rules applicable to excess deliveries by generators, and contract provisions for economic curtailment. These modifications and the extent to which we accept these modifications are addressed below.

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[48] SDG&E submitted on June 14, 2013.

5.1. Solicitation Documents – Commission Approval Required to Modify 2014 Solicitation Documents

In today's decision, we clarify that an IOU may modify the solicitation materials approved under 399.13(a)(1) today with Commission approval.

In its 2014 draft RPS Plan, PG&E states,

> Given the dynamic nature of the renewables industry, market, and regulatory environment, PG&E may make modifications to the 2014 Solicitation Protocol and 2014 RPS Form PPA (Power Purchase Agreement) as market conditions evolve prior to solicitation issuance in order to minimize operational challenges, maximize the value of projects to PG&E customers, and minimize any potential future contract disputes.[49]

CalWEA claims that PG&E's statement is inconsistent with the Commission's statutory obligations under § 399.13 to review and approve RPS procurement plans.[50]

We clarify that, after an IOU obtains § 399.13 approval of an RPS Procurement Plan, any changes to the solicitation materials or other documents included therein must be approved by the Commission. Nothing in statute prevents the Commission from approving changes to the RPS procurement plans after the Commission "accepts, modifies, or rejects" the RPS Plans under § 399.13(a)(1).

Accordingly, in the final RPS Procurement Plans filed pursuant to the schedule adopted herein, PG&E, SCE, and SDG&E shall obtain Commission approval to change the materials included in the Plans after the Commission approves the RPS Procurement Plans under § 399.13(a)(1). After the Plans are

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[49] PG&E June 4, 2014 Draft RPS Procurement Plan at 70.

[50] CalWEA July 2, 2014 comments at 2-3.

approved by the Commission, the utilities may seek Commission approval to correct typographical errors, clarify requirements, incorporate directives from the Commission, or other non-material revisions via a Tier 1 Advice Letter.

5.2. Reducing the Minimum Size Threshold for Project Eligibility

In today's decision, we accept the proposal by SCE to reduce the minimum size threshold for project eligibility to 500 kilowatts (kW). We do not accept SCE's suggestion that we modify the RPS Program now to accommodate any future decision by the Commission related to SB 43 and programs referred to as green tariff programs.

In SCE's amended draft RPS Plan, SCE proposes to reduce the minimum project size eligible to bid into the 2014 RPS solicitation from 1.5 MW to 500 kW to conform to the project size defined in its Green Rate Program pending before the Commission in the consolidated proceeding of Application (A.) 12-01-008, A.12-04-020, and A.14-01-007.[51] Parties did not file comments on this issue.

The IOUs also requested the authority to conform the RPS Program to the green tariff programs pursuant to SB 43 that the Commission may adopt at a future date.

We permit the IOUs to reduce the minimum project size to 500 kW. We do not make this modification, however, to conform the RPS Program to any green tariff program that may be adopted by the Commission. Instead, we make this change in an effort to provide smaller projects with additional market opportunities. While we have, in the past, made an effort to establish a minimum size of the RPS Program so as not to overlap with the Feed-In Tariff

[51] SCE's August 20, 2014 Amended Draft 2014 RPS Procurement Plan at 50.

Program, today we find that permitting multiple bidding forums may strengthen the market for smaller projects.[52] SCE may be suggesting that projects of 500 kW could seek to bid into the 2014 RPS solicitations, and we do not seek to discourage the participation of smaller projects in the RPS annual solicitation. Therefore, we decrease the minimum project size to 500 kW for all future solicitations.

We decline the request to provide IOUs with the authority to modify the RPS Program to conform to any SB 43 green tariff program and direct the IOUs to seek any needed conforming changes after the Commission adopts a green tariff program.[53]

Accordingly, in the final 2014 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E, SCE, and SDG&E shall reduce the minimum threshold for project size eligibility to 500 kW. The modification shall apply in all future RPS Procurement Plans until the Commission directs otherwise.

5.3. Time-of-Delivery Factors

In today's decision, we accept the proposal by SCE to rely on one set of TOD factors. We also accept PG&E's proposal to rely on two sets of TOD factors, one set of TOD factors for energy-only and another set of TOD factors for Full Capacity Deliverability Status (FCDS). We do not accept SDG&E's proposal to

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[52] D.12-11-016, *Decision Conditionally Accepting 2012 Renewables Portfolio Standard Procurement Plans* (November 8, 2012) at 44.

[53] *See*, consolidated Application proceeding, A.12-01-008, A.12-04-020, and A.14-01-007 filed by PG&E, SCE, and SDG&E. On September 30, 2013, the governor signed SB 43 (Wolk, Stats. 2013, ch. 413) (known as the California Shared Renewable Bill) and codified in § 2833(d)(1). The law requires that the three IOUs together procure 600 MW renewable projects of 20 MW or less by 2020, although 100 of that mandate must be met by 1 MW or less.

rely on the flat TOD factor of 1.0 for purposes of contract pricing. With respect to all future updates to TOD factors, we approve of SDG&E's proposal to grant IOUs the authority to apply any Commission-approved updated TOD factors to all RPS procurement programs, including, but not limited, to RAM and the Feed-In Tariff program,[54] known as the Renewable Market Adjustment Tariff (Re-MAT).

TOD factors are applied to contract prices to reflect the higher value of generation supplied during on-peak hours and the lower value of generation supplied during off-peak hours. TOD factors are also applied in LCBF.

SCE proposes one set of TOD factors that apply to all projects consistently, regardless of deliverability status, technology, or any other characteristics. In 2013, we approved SCE's request to differentiate TOD factors based on whether the project was energy-only or FCDS.

SDG&E proposes to revise its TOD factors to a flat amount of 1.0 across all TOD factors for the purpose of contract pricing.[55] SDG&E proposes to continue to use differentiated TOD factors in the LCBF project valuation process to identify the resources that best correspond with portfolio needs.[56] SDG&E states that its flat amount proposal will result in a flat TOD factor for contracts going forward but that this change will make no difference in the amount paid to developers. SDGE supports its proposal on the basis that a Flat TOD will serve

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[54] The Feed-In Tariff program or Re-MAT was implemented by the Commission in D.12-05-035, as modified, pursuant to § 399.20

[55] SDG&E June 6, 2014 Draft RPS Procurement Plan at 28.

[56] SDG&E June 6, 2014 Draft RPS Procurement Plan, Attachment A at 27-29.

to discourage over-generation during peak periods.[57] This proposal is made to address efforts by generators to minimize the cost of their bid by providing a generation profile that places more generation in the off-peak hours than is realistic.[58]

SDG&E also requests the Commission's authority to update its TOD factors and to apply these updated factors to all renewable generation programs so that TOD factors match in all renewable procurement programs.[59]

SCE implemented the use of different TOD factors for FCDS and energy-only projects in its 2013 RPS solicitation, but SCE's experience with the use of two sets of TOD factors revealed that, in certain instances, disincentives were created for certain technologies to switch to FCDS and also resulted in wind facilities receiving less revenue despite the additional benefits in the form of RA benefits.[60] SCE suggests that switching back to a single set of TOD factors that apply to all projects will ensure that different technologies are treated consistently with respect to obtainment of FCDS.[61] CalWEA supports SCE's proposal and encourages the Commission to direct the other two IOUs to do the same.[62] SCE also revised its TOD factors in other ways, such as revising the

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[57] SDG&E June 6, 2014 Draft RPS Procurement Plan at 28.

[58] SDG&E June 6, 2014 draft RPS Procurement Plan at 27; SDG&E 2013 RPS Procurement Plan at 37.

[59] SCE June 4, 1024 Draft RPS Procurement Plan at 51-52.

[60] SCE June 4, 2014 Draft RPS Procurement Plan at 18-19.

[61] SCE June 4, 2014 Draft RPS Procurement Plan at 19.

[62] CalWEA July 2, 2014 comments at 10-11.

definition of peak period to later in the day based on the results of the 2013 Loss of Load Expectation study.[63]

PG&E prefers to continue to rely on two different sets of TOD factors, one for energy-only and another set for FCDS.

Regarding SDG&E's proposal, we appreciate SDG&E's efforts to balance the interests of ratepayers and project developers. However, we decline to adopt the proposal for a flat TOD factor of 1.0 at this time because further insights into the impacts on generation are needed. SDG&E is directed to submit revised TOD factors or rely on those factors already approved in 2013.

We accept SDG&E's proposal to provide the IOUs with authority to update their TOD factors across all programs to maintain consistency because this will promote fairness.

We accept SCE's proposal to rely on one set of TOD factors. We find that SCE's proposal provides a potentially straightforward means of discouraging manipulation of the bid prices and generations profile.

We will permit PG&E to continue to use two sets of TOD factors and to update these TOD factors. While we see benefits in SCE's proposal to rely on a single set, we also view each IOU's proposals as meeting its unique resource and market needs. For this reason, we refrain from requiring uniformity on this issue.

We will revisit TOD factors in 2015.

Accordingly, in the final 2014 RPS Procurement Plans, PG&E is authorized to rely on two sets of TOD factors, energy-only and FCDS as set forth in its 2014

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[63] SCE June 4, 2014 Draft RPS Procurement Plan at 52.

draft RPS Procurement Plan. SCE is authorized to rely on a single set of TOD factors as set forth in its 2014 draft RPS Procurement Plan. SDG&E shall update its TOD factors and remove the flat-rate component. In addition, PG&E, SCE and SDG&E are authorized to file Tier 1 Advice Letters,[64] as needed, to request the Commission to approve of conforming TOD factors across all their RPS procurement programs.

5.4. Project Design Changes

In this decision, we approve SCE's proposal to incorporate a provision in its pro forma contract regarding project design changes. Additionally, we permit PG&E and SDG&E to incorporate a similar provision.

SCE proposes to include a provision in its 2014 RPS pro forma contract that provides SCE the right to review material changes to the generating facility and accept or reject the changes at its sole discretion.[65]

IEP objects to SCE's proposed modification asserting that allowing SCE absolute veto power over all material design changes is unreasonable and, as drafted, gives SCE too much authority over the design of projects.[66] In comments, IEP alternatively suggests SCE be required to identify and justify the types of design changes that affect its interests under the Power Purchase Agreement (PPA) and that the proposed language be modified to remove

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[64] The term *Advice Letter* is addressed by the Commission in General Order 96-B, and this General Order available on the Commission's website.

[65] SCE August 20, 2014 Amended Draft RPS Procurement Plan, Appendix G.1 - Pro Forma, Section 3.11(d).

[66] IEP July 2, 2014 comments at 8.

references to "sole discretion," and instead require SCE to "reasonably exercise its discretion."

In response, SCE states that the proposed modification is clarifying language that does not represent an expansion of its rights compared to its 2013 RPS pro forma agreement.[67] SCE states that it is reasonable that sellers not have the right to make material design changes because SCE selects projects based on a competitive bidding process and material changes after selection and execution may harm SCE's customers, as changes may increase ratepayer costs or diminish the PPA's value. Additionally, SCE states that the modification has previously been approved for its RAM 5 pro forma agreement.[68]

We agree with SCE that the proposed modification to Section 3.11(d) of its 2014 RPS Procurement pro forma contract is a clarification and, moreover, we find it reasonable for SCE to have the right to review and accept or reject material changes at its sole discretion. SCE must act reasonably and must not reject proposals arbitrarily.[69] The generating facility information referred to in Section 3.11(d) includes, but is not limited to, project site location, photovoltaic module specification, and major electrical equipment specification. These project design details are set forth in the executed PPA, and as such, we agree that SCE has the right to review and accept or reject the design changes. Not only does SCE evaluate a project based on a certain project design but the Commission approves the contract expecting a certain value and cost to ratepayers.

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67 SCE July 30, 2014 reply comments at 11.

68 SCE July 30, 2014 reply comments at 11, referring to CPUC Resolution E-4655 at 26.

69 IEP November 10, 2014 at 2.

Additionally, a design change would be an amendment to the contract which requires SCE consent and could also require Commission approval.

Accordingly, in the final 2014 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, SCE is permitted to include the proposed modification to Section 3.11(d) of its 2014 RPS Procurement pro forma agreement. Additionally, PG&E and SDG&E are permitted to include similar provisions in their final 2014 RPS Procurement Plans.

5.5. Tax Incentives

We reject SCE's proposal to remove language related to expiring federal tax credits (the Investment Tax Credit and the Production Tax Credit)[70] in the pro forma contract.

In its 2013 pro forma contract, SCE provided for the possible extension of the commercial operation deadline of a project and/or a termination right for sellers in the event federal tax credit legislation was not extended beyond 2016 on terms similar to those available to project at the time the contract is executed.[71] In its 2014 RPS draft Plan, SCE removes references to the federal tax credits because for a seller to qualify for the Investment Tax Credit, in the credit's current form, the project must achieve commercial operation by a date it deems largely unattainable, December 31, 2016.[72] Achieving operation by this date is unlikely given the expected timing of a 2014 RPS solicitation but not impossible.

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70 The Investment Tax Credit is a federal tax credit for eligible renewable and other technologies. 26 U.S.C. § 48.

71 SCE June 4, 2014 Draft RPS Procurement Plan at 51-52.

72 SCE June 4, 2014 Draft RPS Procurement Plan at 51-52.

SCE removes the provisions regarding the Production Tax Credit because that tax credit, in its current form, expired.[73]

IEP states that removal of the provisions is shortsighted and may cause unnecessary complications during contract negotiation.[74] IEP recalls that the Investment Tax Credit and Production Tax Credit have lapsed in the past and subsequently been extended by new federal legislation. IEP states that Congress may extend the credits again, beyond 2016.[75]

We reject SCE's proposal to remove the provisions. Since it is still potentially feasible for some projects to qualify for the available tax credits and since there is a history of last-minute changes to these federal tax credit provisions, we find it premature to remove this language now but may revisit this next year.

Accordingly, in the final 2014 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E, SCE, and SDG&E shall not remove the provisions related to the federal tax credits, the Investment Tax Credit and the Production Tax Credit.

5.6. SDG&E's Request to Not Hold a 2014 Solicitation and Update Solicitation Materials

In its June 6, 2014 draft RPS Procurement Plan, SDG&E requests not to hold a 2014 RPS Solicitation. We accept this request for 2014. SDG&E is required to first seek the Commission permission before entering into any bilateral

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73 SCE June 4, 2014 Draft RPS Procurement Plan at 51-52; SCE July 30, 2014 reply comments at 13.

74 IEP July 2, 2014 comments at 8-9.

75 IEP July 2, 2014 comments at 8-9.

contracts during the time period covered by SDG&E's 2014 RPS Procurement Plan. In addition, should SDG&E determine that an RPS solicitation is needed during the time period covered by the 2014 solicitation cycle, SDG&E is required to first seek Commission permission.

Each utility remains responsible for meeting its RPS Program procurement requirements. The Commission implemented these requirements, as directed by statutory law, in D.11-12-020.

SDG&E explains that for Compliance Period 2011-2013, SDG&E has met its obligations, has filed all required compliance documentation, and it is waiting for confirmation from the Commission.[76] Regarding Compliance Period 2014-2016, SDG&E expects it will meet its RPS goals with generation from executed contracts and deliveries from utility-owned generation.[77] Regarding Compliance Period 2017-2020, based on current probability-weighted RPS position forecast, SDG&E states that it may not require additional procurement and will continue to monitor a multitude of factors to assess its future needs.[78] In further explaining its approach to meeting the RPS goals of Compliance Period 2017-2020, SDG&E states that the level of new purchases required will be a function of portfolio performance and will be subject to the level of banking, if any, related to potential excess procurement in Compliance Period 2014-2016 into Compliance Period 2017-2020.

SDG&E also states its intention to fill any remaining RPS need with viable low-cost opportunity from future solicitations, bilateral transactions, and

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[76] SDG&E June 6, 2014 Draft RPS Procurement Plan at 16.

[77] SDG&E June 6, 2014 Draft RPS Procurement Plan at 16.

[78] SDG&E June 6, 2014 Draft RPS Procurement Plan at 16.

potential investments, and will continue to procure from mandated programs to the extent required. SDG&E intends to manage potential over-procurement by banking it for future compliance needs, terminating contracts where conditions precedent are not met or where mutual agreement is reached, and/or selling excess procurement.[79] Should SDG&E determine that it has an unmet RPS need during the 2014 solicitation cycle, SDG&E should file a motion in this proceeding.

While SDG&E does not anticipate the need to hold a solicitation, it offers updates to the solicitation materials used in 2013 in an effort to keep these materials current.

We find SDG&E's evaluation of its current RPS procurement needs relative to its request not to hold a 2014 solicitation is reasonable. Should SDG&E determine that an RPS solicitation or bilateral contracts are needed during the time period covered by the 2014 solicitation cycle, 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 today solely exempts SDG&E from the annual solicitation requirement for one year, 2014. SDG&E will present another RPS procurement scenario in 2015.

In addition, we agree with SDG&E that updating its solicitation materials and pro forma contract is important even if no solicitation is planned for 2014, and we approve of the changes as discussed elsewhere in this decision. Updating these documents will promote transparency.

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[79] SDG&E June 6, 2014 Draft RPS Procurement Plan at 15.

Accordingly, SDG&E is authorized not to hold a 2014 RPS solicitation and shall indicate in its Final 2014 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 RAM), during the time period covered by the 2014 solicitation cycle. SDG&E shall file a final 2014 RPS Procurement Plan with updated solicitation material even though no solicitation is scheduled for 2014. This authorization to not hold a solicitation only applies for one year.

5.7. Shortlist Exclusivity

In today's decision, we reaffirm our finding in D.13-11-024 that the contract negotiating arrangement referred to as *shortlist exclusivity* will not be permitted.[80]

Shortlist exclusivity, as used here, refers to that point in time during the contract negotiation process when sellers (with projects on more than one utility's shortlist) are only permitted to negotiate with one potential buyer/utility. This arrangement could be described as the seller offering exclusive negotiating rights to the utility.[81] This arrangement was first addressed by the Commission in D.04-07-029.[82] At that time, we found that exclusivity was needed to prevent sellers from seeking increasingly higher prices from multiple utilities during the negotiation process since the renewable generation market

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80 D.13-11-024, *Decision Conditionally Accepting 2013 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan and On-Year Supplement* (November 20, 2013) at 31-32.

81 D.13-11-024, *Decision Conditionally Accepting 2013 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan and On-Year Supplement* (November 20, 2013) at 31-32.

82 D.04-07-029, *Opinion Adopting Criteria for the Selection of Least-Cost and Best-Fit Renewable Resources* (July 8, 2004).

was relatively small.[83] We modified our position in D.13-11-024. Now, utilities cannot require shortlist exclusivity.

SCE suggests that the Commission again permit shortlist exclusivity for a limited period time, 90 days during contract negotiation. SCE makes this proposal in conjunction with its proposal to restrict the size of its solicitation shortlist to the most competitive projects based on quantitative and qualitative characteristics.[84] SCE proposes to add shortlist exclusivity to promote full realization of the benefits of limiting its shortlist to projects with which it is likely to execute a contract.[85]

In response to SCE's request, we reaffirm our finding in D.13-11-024 that utilities shall not require shortlist exclusivity as part of the shortlist and contract negotiation process because the RPS solicitation process is highly competitive and involves many potential sellers.[86] As a result, in a highly competitive market, there is less risk that sellers will be in a position to obtain a higher price by simultaneously negotiating with more than one utility.[87] SCE claims that this rationale is not applicable to the more selective shortlisting process set forth in its 2014 draft RPS Plans because instead of proposing exclusivity out of concern of

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83 D.04-07-029, *Opinion Adopting Criteria for the Selection of Least-Cost and Best-Fit Renewable Resources* (July 8, 2004) at 8. .

84 SCE June 4, 2014 Draft RPS Procurement Plan at 48.

85 SCE June 4, 2014 Draft RPS Procurement Plan at 49.

86 D.13-12-024, *Decision Conditionally Accepting 2013 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan and On-Year Supplement* (November 20, 2013) at 31-32.

87 D.13-12-024, *Decision Conditionally Accepting 2013 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan and On-Year Supplement* (November 20, 2013) at 31-32.

high prices, SCE claims that it is proposing exclusivity to promote reduced transaction costs.[88]

SCE may be correct that exclusivity will reduce transaction costs but we continue to find it an unnecessary restriction on the market based on the current level of competition.

Accordingly, consistent with D.13-12-024, in the final 2014 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E, SCE, and SDG&E are not authorized to require shortlist exclusivity as part of the contract negotiating process.

5.8. Excess Deliveries

In this decision, we approve of SCE's request to modify its pro forma contract terms related to excess deliveries as well as PG&E's and SDG&E's similar requests on the basis that the modified contract terms propose a reasonable means to control expected contract costs.

SCE proposes to reduce the amount of contract capacity for which it will pay a seller from 110% of contract capacity to 100% of contract capacity.[89] Additionally, SCE proposes to modify how the amount to be paid for deliveries in excess of 115% of the expected annual net energy production will be calculated.[90] Instead of SCE paying the seller 75% of the contract price, SCE proposes that the seller be paid CAISO revenues and costs for the excess

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[88] SCE June 4, 2014 Draft RPS Procurement Plan at 49.

[89] SCE August 20, 2014 Amended Draft RPS Procurement Plan, Appendix G.1, pro forma contract at Section 1.06(c)(i).

[90] SCE August 20, 2014 Amended Draft RPS Procurement Plan, Appendix G.1, pro forma contract at Section 1.06(c)(ii).

deliveries. PG&E and SDG&E have similar excess delivery pro forma contract terms that adjust the amount a seller is paid for excess deliveries.[91]

SCE states that the changes to its excess capacity provision will limit customer exposure to incremental costs and that, if a seller would like to produce more energy, then they should offer a higher contract capacity during the bidding process.[92]

In comments, PG&E supports SCE's proposed terms because it is one way in which IOUs can ensure that sellers do not intentionally overbuild their facilities with the expectation that they can deliver the excess generation.[93] IEP states that the modification is not needed because the seller's interconnection agreement already includes limitations and that intermittent resources cannot predict their energy generation with absolute precision.[94] IEP also states that the proposal produces a windfall for SCE because SCE would be paying nothing but would still be receiving a renewable energy credit that could be used to meet its RPS requirements.[95] SCE agrees with IEP that the interconnection agreement has limitations and that, as proposed, the modified provisions will better align with interconnection agreements.[96]

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[91] PG&E August 20, 2014 Amended Draft RPS Procurement Plan, Appendix 4, pro forma contract at Section 4.4 and SDG&E 2014 Draft RPS Procurement Plan, Appendix 6, pro forma contract at Section 4.2.

[92] SCE August 20, 2014 Amended Draft RPS Procurement Plan at 58.

[93] PG&E July 30, 2014 reply comments at 29.

[94] IEP July 2, 2014 comments at 5.

[95] IEP July 2, 2014 comments at 5.

[96] SCE July 30, 2014 reply comments at 8.

SCE presents a similar rationale for modifying its excess delivery terms as it makes for its excess capacity modification. SCE states that the modifications to its excess deliveries terms related to annual net energy production reduce incentives for sellers to over-install capacity that cause excess costs to ratepayers.[97] IEP opposes the excess delivery terms asserting that SCE's approach fails to incent maximum level of energy production from RPS-eligible resources.[98] Additionally, IEP recommends that the Commission should maintain SCE's 2013 pro forma contract provisions or adopt one of IEP's alternate suggestions.[99] In support of SCE's provisions, PG&E states that the provisions reasonably accommodate for weather variation and that SCE's proposed provision in combination with contract capacity and the guaranteed energy production provisions represent lower and upper bounds of contract volumes.[100]

We find the excess delivery terms proposed by SCE, PG&E and SDG&E reasonable on the basis that the seller and utility agree on a contract quantity and it is reasonable to expect that the seller will construct a facility consistent with the terms of the contract. Additionally, we find it reasonable that the contracts have both lower and upper bounds for energy deliveries. When executing a contract, the seller and buyer agree to certain terms, including capacity and expected generation. Additionally, the utility assumes a certain amount of generation when calculating future procurement needs. While deliveries may reasonably

[97] SCE August 20, 2014 Amended Draft RPS Procurement Plan at 59.

[98] IEP July 2, 2014 comments at 7.

[99] IEP July 2, 2014 comments at 7.

[100] PG&E July 30, 2014 comments at 30.

vary for weather or other issues, we find the terms reasonably accommodate such variations and that the proposed terms reasonably limit ratepayer exposure to excess costs due to excess deliveries of a particular contract and/or excess procurement from inaccurate renewable net short forecasts. Moreover, the IOUs should reasonably administer and enforce the contracts such that if sellers are not abiding by the terms of the contract, ratepayers are not subject to excessive costs or other harms.

Accordingly, in the 2014 RPS Procurement Plans filed with the Commission pursuant to the schedule adopted herein, PG&E, SCE, and SDG&E are authorized to incorporate the excess delivery terms set forth in the draft plans.

5.9. Economic Curtailment

Today, we approve of the utilities' curtailment terms and conditions set forth in their proposed 2014 RPS pro forma contracts. Additionally, we accept SCE's proposal to require two bid offer variants related to economic curtailment. We also require PG&E to modify its solicitation protocol to require at least two economic curtailment variants for each bid and to clarify how it will value economic curtailment. In addition, we require the utilities to include in their 2014 RPS solicitation shortlist reports the curtailment variants received and how the amount of curtailment offered impacted the utilities' shortlisting of bids.

The Commission first addressed economic curtailment in D.11-04-030, which approved the utilities' 2011 RPS Procurement Plans. The Commission additionally addressed the issue in D.13-11-024 in approving of the utilities' 2013 RPS Procurement Plans. In those decisions, we focused on how the terms would allocate risk between the seller, buyer, and ratepayer and emphasized that the terms should reduce ratepayer exposure to negative locational marginal pricing and result in a financeable contract. As a result of experience with previous terms and CAISO updating its tariff due to Order 764 of the Federal Energy Regulatory Commission, the utilities now state it is necessary to modify their economic curtailment terms and conditions.

PG&E, SCE, and SDG&E address the issue of curtailment several times in their 2014 RPS Procurement Plans. First, the utilities address curtailment in terms of meeting their RPS requirements and Renewable Net Short Calculations. Both PG&E and SCE note that they account for curtailment in their forecasts for expected generation.[101] Additionally, SDG&E reports that it observed increases in the frequency of negative locational marginal pricing, which resulted in curtailment of resources.[102]

PG&E, SCE, and SDG&E also address the issue of curtailment in their updated pro forma contract included with their draft 2014 RPS Procurement Plans. These 2014 RPS Procurement Plans include modified provisions regarding economic curtailment. The proposed economic curtailment terms vary between the utilities. PG&E's pro forma contract includes provisions for the seller and buyer to agree to the number of hours that may be curtailed per year and the amount to be paid for the energy that would have been delivered, if not curtailed.[103] SCE's 2014 pro forma contract reflects that either up to

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101 PG&E's June 6, 2014 Draft 2014 RPS Procurement Plan at 53 and SCE's August 20, 2014 Amended Draft 2014 RPS Procurement Plan at 32.

102 SDG&E's June 4, 2014 Draft 2014 RPS Procurement Plan at 30.

103 PG&E's August 20, 2014 Update to Draft RPS Procurement Plan, Appendix 4, Section 3.1(o); and PG&E's protocol instructs that the PG&E pro forma PPA requires unlimited curtailment, but will accept offers with a minimum of 250 hours per year of economic curtailment (PG&E's Draft 2014 RPS Procurement Plan), Appendix H, at 28.

50 hours per year of unpaid economic curtailment rights and any hours above 50 will be compensated at the contract price or unlimited economic curtailment rights that will be compensated at the contract price.[104] Similarly, SDG&E's 2014 pro forma contract reflects unlimited economic curtailment rights and SDG&E will pay the contract price for any generation that would have occurred if not economically curtailed.[105]

The third reference to economic curtailment occurs when PG&E and SCE incorporate economic curtailment in their solicitation protocols with regards to how offers are to be submitted and how they will be evaluated. In its RPS solicitation protocol, SCE requires bidders to provide offers with two variants where one offer variant includes 50 hours of unpaid curtailment and the other variant is for paid unlimited curtailment.[106] Additionally, both PG&E and SCE incorporate economic curtailment in their LCBF methodologies. Both PG&E and SCE consider economic curtailment in the LCBF calculation of an offer's energy value.[107] PG&E also considers the amount of curtailment hours offered by a bidder as an element of its portfolio adjusted value.[108]

Parties provide comments on the various PPA terms and SCE's bidding requirements regarding the ability to obtain financing based on the pro forma,

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104 SCE's August 20, 2014 Amended Draft RPS Procurement Plan, Appendix G.1, Section 3.12(g).

105 SDG&E's June 4, 2014 Draft RPS Procurement Plan, Appendix 6, pro forma PPA Section 3.4.

106 SCE's August 20, 2014 Amended Draft RPS Procurement Plan, Appendix F.1 at 11.

107 PG&E's June 6, 2014 Draft RPS Procurement Plan, Attachment K at 3 and SCE's Amended Draft 2014 RPS Procurement Plan, Appendix I.1 at 4.

108 PG&E's June 6, 2014 Draft RPS Procurement Plan, Attachment K at 11.

the complexity of terms and the bidding requirements, fairness of the terms to sellers, the lack of inclusion of the production tax credits, and lack of clarity regarding how offers will be evaluated and economic curtailment terms operationalized. Specifically, CalWEA, LSA, and IEP object to unlimited curtailment provisions because they were previously rejected and because curtailment provisions need to be bound for a contract to obtain financing.[109] SDG&E asserts that its provisions are financeable and that there is a need for unlimited curtailment rights because the negative cap on locational marginal pricing has increased to -$150/MWh versus the previous -$30/MWh cap resulting in increased negative price exposure for the buyer and ratepayer.

CalWEA, IEP, and Iberdrola also recommend that contracts provisions be modified to compensate sellers for expired or soon-to-be expired production tax credits because those projects are disproportionately impacted.[110] PG&E asserts that this is not necessary because PG&E allows sellers to negotiate the price to be paid for economically curtailed generation, which could take into consideration the expired production tax credits.[111] SDG&E agrees with PG&E.[112] Additionally, Reid states that circumstances have not changed from when the Commission previously addressed this issue and, therefore, requiring compensation for expired production tax credits should be rejected.[113]

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109 CalWEA July 2, 2014 comments at 7; IEP July 30, 2014 comments at 11; and LSA July 2, 2014 comments at 2.

110 CalWEA July 2, 2014 comments at 4; IEP July 30, 2014 comments at 10; and Iberdrola July 2, 2014 comments at 4.

111 PG&E July 30, 2014 comments at 23.

112 SDG&E July 30, 2014 comments at 3.

113 Reid July 30, 2013 comments at 16.

Finally, LSA comments that it is unclear how PG&E will value bids that offer less than full operation flexibility and that SCE's multiple bidding options overly complicate the bidding process.[114] In reply comments, SCE states that the multiple options do not complicate the bidding process because the options are not difficult to understand.[115] In addition, SCE agrees, in part, with LSA that fewer curtailment options make sense, but that the multiple options could help determine the value of a curtailment cap.[116]

The Commission is encouraged that the IOUs are addressing and incorporating the issue of economic curtailment in multiple aspects of their 2014 RPS procurement plans. As referenced above, the utilities note in their 2014 RPS procurement plans that they are observing increasing occurrences of negative locational marginal pricing and, in some limited instances, working to minimize or avoid the need for curtailment. The utilities should continue to report on such observations and actions as well as any analysis and forecasting of curtailment needs that are now being completed. We envision that reports to the Energy Division could include the following, as relevant:

- Written description of any quantitative analysis of estimates of the number of hours per year of negative market pricing for the next 10 years.
- Metrics used to characterize the incidences of overgeneration and negative market price periods.

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[114] LSA July 2, 2014 comments at 3.

[115] SCE July 30, 2014 comments at 12.

[116] SCE July 30, 2014 comments at 13.

- Factors having the most impact on the projected increases in incidences of overgeneration and negative market price hours.
- Experience, to date, with managing ratepayer exposure to negative market prices.
- Direct costs incurred to ratepayers, to date, for incidences of overgeneration and associated negative market prices.
- Overall strategy for managing the ratepayer cost impact of increasing incidences of overgeneration and negative market prices.

Additionally, reporting to the utilities' Procurement Review Group (PRG) on frequency of economic curtailment, temporal (annual and daily) trends, locational trends, costs, etc., should be done on a regular basis.

We also expect the utilities to continue to examine causes of negative pricing occurrences, opportunities and alternatives to avoid and/or minimize economic curtailment, including ways to minimize risk to ratepayers.

As noted above, the IOUs all propose different pro forma contract provisions related to economic curtailment. The IOUs request contract modifications based on experiences related to administering and negotiating economic curtailment terms and conditions. While these changes are consistent with IEP's recommendation that the utilities should fine-tune curtailment provisions based on practical experience over time, it is unclear if moving towards fully-compensated, unlimited economic curtailment is the best option for the ratepayer given that little information exists on the value and cost of the provisions, as well as, the need for economic curtailment in the future.

While the provisions protect ratepayers from negative locational marginal pricing, ratepayers are exposed to costs for generation that is never received. Overall, though, we agree with the utilities that the provisions, as proposed, do provide some ratepayer protection against the risk of negative locational marginal pricing and allow the contracts to be financeable.

As for whether the provisions should be modified to include compensation for production tax credits, we agree with Reid, that circumstances have not significantly changed from when we first addressed this issue. As such, the utilities are not required to compensate the seller for production tax credits that would have been received if generation were not economically curtailed.

Further, we agree with LSA that it is not clear how PG&E will value offers that include less than full operational flexibility. Specifically, PG&E's portfolio adjusted value adder description for curtailment hours notes a wide variety of costs that this portion of the adder is to account for, including operational costs, imbalance energy charges, and ancillary services. It is unclear how the adder will be calculated based on these various costs, what references or sources will be used in calculating the costs, whether costs will vary based on technology, and even whether the amount of curtailed hours offered will affect the adder calculation or if the adder is a single value. Therefore, we direct PG&E to modify its 2014 RPS solicitation protocols to clarify how its curtailment hours adder will be calculated.

SCE comments that value exists in having curtailment options based on the lack of market data related to the need for economic curtailment. We agree and find that it is reasonable to require multiple variants of an offer for the purpose of gaining market information.

Therefore, PG&E shall modify its 2014 RPS solicitation protocols to require bidders to provide two variations of an offer with the variants offering different amounts of annual economic curtailment hours. Additionally, PG&E and SCE shall address how pricing and value varied with regards to different curtailment hour amounts in their 2014 RPS solicitation shortlist reports and how the amount of hours offered affected their proposed 2014 RPS solicitation shortlists. Further, if any additional considerations related to economic curtailment, such as viability, project location, transmission, etc. are incorporated into the utilities' shortlisting decisions, those considerations should additionally be reported. The Energy Division is authorized, if needed, to direct the utilities to adhere to specific economic curtailment shortlisting reporting requirements as adopted herein.

Accordingly, PG&E, SCE, and SDG&E shall continue to incorporate and describe how expected economic curtailment affects their RPS procurement in future RPS procurement plans. Additionally, the utilities' terms and conditions of the pro forma related to economic curtailment are approved as proposed. PG&E shall modify its RPS protocols such that each offer is to include at least two variants that offer different amounts of economic curtailment hours. PG&E shall also modify its LCBF description of its Curtailment Hours adder such that it is clear how bids will be evaluated if they offer less than full economic curtailment rights. PG&E and SCE shall include in their 2014 RPS solicitation shortlist reports information regarding how the offers' economic variants differed and how economic curtailment was considered in their shortlisting processes.

6. Proposals in March 26, 2014 ACR

The March 26, 2014 ACR included several proposals regarding the RPS Program. We address these proposals below.

6.1. Project Development – New RPS Bid Solicitation Requirement

In this decision, we require the IOUs' bid solicitation materials be modified to include a bid requirement that projects have, at a minimum, achieved the "application deemed complete" (or equivalent) status under the land use entitlement process by the agency designated by the California Environmental Quality Act or National Environmental Policy Act as the *lead agency* to be eligible to bid into the annual RPS solicitation.[117] This means that project's application has been deemed by the lead land use authority (*e.g.,* Local Government, California Energy Commission, Bureau of Land Management) to have sufficient information to initiate the land use permitting process. This new requirement provides IOUs with an indication of project readiness of the project to move forward and, as such, is a reasonable requirement for projects that intend to be successfully developed. This requirement does not apply to projects if CEQA or NEPA is not applicable or no *lead agency* is designated under the law.

The March 26, 2014 ACR requested that parties comment on whether, as a prerequisite showing, projects should complete the Initial Study portion of its environmental review under CEQA and/or under the NEPA before participating in the annual RPS solicitations.

In comments, most parties recommend against adopting the proposed requirement.[118] Parties opposing the proposed requirement of having a

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[117] Joint Conservation Parties (Nature Conservancy, Defenders of Wildlife, and Natural Resources Defense Council) November 10, 2014 comments at 1; PG&E November 10, 2014 comments at 12; CEERT November 10, 2014 comments at 4.

[118] CalWEA July 2, 2014 comments at 16; CEERT July 2, 2014 comments at 22; Iberdrola July 2, 2014 comments at 3; IEP July 30, 2014 reply comments at 10; LSA July 2, 2014 comments

Footnote continued on next page

completed the CEQA or NEPA Initial Study state that the requirement is unnecessary from a project viability perspective because now projects are showing increased viability, the project viability calculator (PVC) incorporates a project's permitting progress, contracts have project development milestones, and projects are required to have a Phase II transmission study (or equivalent) to participate in an RPS solicitation.

Additionally, parties state that the proposal is unreasonable because not all projects have a CEQA or NEPA Initial Study and, as a result, this requirement would exclude a significant number of projects from participating in RPS solicitations creating a potential for decreased market participants and increased costs for ratepayers. Lastly, opposing parties suggest that the proposed requirement will not promote more environmentally benign projects or increased project success because only a very few projects terminate based on environmental issues or the projects achieves CEQA or NEPA review before termination.

The Nature Conservancy, Defenders of Wildlife, and Natural Resources Defense Council (Joint Conservation Parties) jointly support the proposal in concept but suggest an alternative requirement of "application deemed complete." This alternative is also supported by the Farm Bureau.[119] The Joint Conservation Parties agree with the majority of parties that not all projects would have Initial Studies under CEQA or NEPA and suggest that an

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at 7; PG&E July 2, 2014 comments at 16; SCE July 2, 2014 comments at 10; and SDG&E July 2, 2014 comments at 4.

119 Joint Conservation Parties July 2, 2014 comments at 1; Farm Bureau July 30, 2014 reply comments at 1.

"application deemed complete" (or equivalent) requirement strikes the right balance between indicating project readiness and supporting a robust RPS market.

We agree with the Joint Conservation Parties that a requirement to have, at a minimum, "application deemed complete" (or equivalent)[120] status within the land use entitlement process as a prerequisite to participating in the 2014 solicitation is a reasonable added requirement that could increase overall project viability while not unnecessarily restricting project participation in the solicitation. This requirement would mean that a project must submit the documentation required by the land use permitting agency showing that the project's application is deemed by the permitting agency to have sufficient information to begin the permitting review process. The Joint Conservation Parties' recommendation addresses the concerns expressed in comments that not all projects have Initial Studies.

Additionally, while we agree with PG&E regarding recent evidence of increased viability in projects and that the PVC addresses some aspects of project viability, this added requirement is a demonstrable step toward site control and ensures that projects are progressing towards development at the time of bidding.

Finally, as the Joint Conservation Parties state, the requirement would be similar to the development of the "discounted core" portfolio of projects in R.13-12-010, the Long-Term Procurement Planning proceeding, where projects

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[120] Local government uses the term "application deemed complete" (California Government Code § 65943); California Energy Commission uses the term "data adequate" (Title 20 CCR § 1709); Bureau of Land Management uses the term "completed application" (43 CFR 2804.25).

that have a power purchase agreement and a complete (*i.e.*, data adequate) application for a major environmental permit are included.[121]

Accordingly, in the final 2014 RPS Procurement Plans filed with the Commission pursuant to the schedule adopted herein, PG&E, SCE, and SDG&E shall modify their 2014 RPS solicitation protocols to require that projects have achieved, at a minimum, an "application deemed complete" (or equivalent) status within the applicable land use entitlement process by the agency designated by the California Environmental Quality Act or National Environmental Policy Act as the *lead agency* as a prerequisite to participating in the 2014 RPS solicitations. This requirement may be fulfilled by the developer providing a copy of the letter from the land use permitting agency documenting that the land use permit application for the project has been "deemed complete" to begin the permitting review process. The requirement shall apply to all future annual RPS Procurement solicitations until the Commission directs otherwise.

6.2. Resource Adequacy Valuation in RPS LCBF Methodology

In today's decision, we decline to adopt the March 26, 2014 ACR proposal that resource adequacy be valued at zero in the utilities' LCBF methodologies for their annual 2014 RPS solicitations. We do require, however, that the utilities report (1) their resource adequacy value price curves and (2) their bid rankings using resource adequacy valuations calculated with net qualifying capacities (NQC) based on the existing exceedance methodology and an effective load carrying capacities capacity (ELCC) methodology.

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[121] Joint Conservation Parties July 30, 2014 reply comments at 2.

The utilities include a valuation of resource adequacy in their LCBF methodologies. The valuation represents the capacity benefits of each bid offer. In the past, the Commission has been specific regarding how utilities value an offer's resource adequacy.[122] More recently, the Commission has allowed the utilities considerable flexibility regarding this valuation, as evidenced by the utilities' varying proposed methodologies.[123] As part of the Long-Term Procurement Plan proceeding, R.13-12-010,[124] the Commission also approves and directs the utilities' procurement of capacity. The resource adequacy valued as part of LCBF evaluations represents capacity that would otherwise need to be purchased as directed in the long-term procurement proceeding.

The March 26, 2014 ACR proposed that utilities account, not only the procurement needs to meet or exceed RPS requirements, but also for overall energy portfolio needs and system requirements. The March 26, 2014 ACR essentially sought to address the intersection of RPS and LTPP, meaning that the utilities' resource adequacy valuations should reflect findings in the LTPP proceeding that, for example, when no need to procure additional capacity exists, this finding should be reflected by having the utilities value resource adequacy at zero in their LCBF methodologies.

Most parties oppose this proposal. These parties state that a facility's resource adequacy is always valuable regardless of whether a need exists for

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122 D.04-07-029, *Establishes Least Cost/Best Fit Bid Ranking Criteria* (July 8, 2004) at 20.

123 SCE's August 20, 2014 Amended Draft RPS Procurement Plan, Appendix F.1 and PG&E's June 6, 2014 Draft RPS Procurement Plan, Attachment K.

124 R.13-12-010, *Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans* (December 19, 2014).

new system capacity.[125] Other parties state that resource adequacy is a defined product with market value and that the lack of need for resource adequacy will be reflected in low resource adequacy values.[126] PG&E and IEP add that resource adequacy valuation is needed to distinguish between energy-only and fully deliverable resources.[127] IEP adds that to change resource adequacy valuation would undermine developer investments and commitments.[128]

Two parties support the proposal, CalWEA and the City and County of San Francisco (San Francisco). These two parties state that resource adequacy valuation should align with LTPP which shows system capacity will exceed the planning reserve margin for at least the next 10 years.[129] San Francisco adds that assigning artificially high resource adequacy value creates market distortions and encourages investment in resources that are not optimally located and require costly transmission upgrades to support deliverability.[130] CalWEA alternatively proposes that if the ACR proposal is not adopted, the Commission should direct the utilities to use ELCC values developed by the consulting company, Energy and Environmental Economics (E3) for calculating resource adequacy values, in addition resource adequacy valuation based on the existing

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125 CEERT July 2, 2014 comments at 21; SDG&E July 2, 2014 comments at 2; SCE July 2, 2014 comments at 9; Calpine July 30, 2014 reply comments at 4.

126 LSA July 2, 2014 comments at 6; PG&E July 2, 2014 comments at 13; PG&E July 30, 2014 reply comments at 19; SCE July 2, 2014 comments at 9; SCE July 30, 2014 reply comments at 7; UCS July 30, 2014 reply comments at 13.

127 PG&E July 2, 2014 comments at 14 and IEP July 30, 2014 reply comments at 8.

128 IEP July 30, 2014 reply comments at 8.

129 CalWEA July 2, 2014 comments at 9 and San Francisco comments at 1.

130 San Francisco July 2, 2014 comments at 3.

exceedance methodology; provide both sets of results to the Commission; and the Commission should approve the utilities' shortlists of bids based on rankings using ELCC capacity values.[131] Several parties oppose CalWEA's alternative on the basis that the Commission has not yet adopted ELCC values.[132]

We agree with LSA, PG&E, and SCE that resource adequacy is a defined product with market value. We also agree with PG&E, SCE, and UCS that the lack of capacity need should be reflected in low resource adequacy values. Further, while ELCC values are being developed by the Commission, the Commission has yet to adopt such values. For this reason, we agree with Reid that CalWEA's suggestion to use ELCC to value resource adequacy should not be adopted at this time. Lastly, we agree with San Francisco, IEP, and CalWEA that important decisions related to transmission investments, project development, and project investment are based on projects having resource adequacy value.

Therefore, we do not adopt the March 26, 2014 ACR proposal to adopt a zero value for resource adequacy in the utilities' 2014 LCBF methodologies. However, given the importance of resource adequacy valuation in the utilities' LCBF methodologies, we direct the utilities to provide more detailed reporting of their resource adequacy valuation.

Accordingly, first, the utilities shall report to their PRGs and the Energy Division their resource adequacy price curve forecasts in their shortlist reports along with a description of the methodology used to develop the curve to ensure that they are consistent with current market resource adequacy values as well as

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131 CalWEA July 2, 2014 comments at 13.

132 Reid July 30, 2014 reply comments at 17; IEP July 30, 2014 reply comments at 9; LSA July 30, 2014 reply comments at 5.

LTPP system need forecasts. The IOUs' shortlist reports shall also include a written explanation of how their resource adequacy price forecast is consistent with the market and LTPP forecasts. Second, while the Commission is considering ELCC in a separate proceeding (R.14-10-010),[133] it may be considered in the RPS proceeding when we re-visit LCBF methodology.[134] Therefore, we adopt CalWEA's alternative proposal, in part, and direct the utilities to report to their respective PRGs two bid rankings. One ranking of all bids received shall be based on resource adequacy valuations calculated with NQC values based on the existing exceedance methodology and the other ranking shall use NQC values based on an ELCC methodology. The ELCC values used may be those developed by E3 or the utility.

6.3. Renewable Integration Cost Adder – Interim Value Adopted

Today's decision adopts an interim renewable integration cost adder for the utilities to employ until the Commission adopts a more comprehensive approach, expected in 2015. More detailed work must be accomplished by the Commission and by the parties before a final valuation methodology is adopted. Completing this valuation process is a top priority for the Commission. To move this process forward, the Commission will consider the final methodology in

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[133] The Commission opened R.14-10-010, the successor proceeding to R.11-10-023, and closed R.11-10-023 at the October 16, 2014 Agenda Meeting.

[134] Section 399.26(d) provides, in full, as follows: "In order to maintain electric service reliability and to minimize the construction of fossil fuel electrical generation capacity to support the integration of intermittent renewable electrical generation into the electrical grid, by July 1, 2011, the commission shall determine the effective load carrying capacity of wind and solar energy resources on the California electrical grid. The commission shall use those effective load carrying capacity resources toward meeting the resource adequacy requirements established pursuant to Section 380."

coordination with R.13-12-010, the Long-Term Procurement Planning proceeding[135] and any other proceeding that may be relevant to the future.

6.3.1. Background

The March 26, 2014 ACR sought comments on various issues and questions related the Commission's consideration of a renewable integration cost adder for use in the LCBF t RPS bid evaluation methodologies.[136] On July 17, 2014, the Energy Division provided the electronic service list in R.11-05-005 with eight additional questions to guide comments by parties when responding to the renewable integration cost adder issues presented in the March 26, 2014 ACR. On July 30, 2014, parties again filed additional comments regarding a renewable integration cost adder.

Increases in intermittent renewable generation may require the grid system to be more operationally flexible to ensure adequate system reliability. The costs associated with making the system more operationally flexible are referred in today's decision as a renewable integration cost adder. In short, a renewable integration cost adder would reflect the cost of integrating renewable resources onto the grid.

In the past, we have recognized the importance of this issue but declined requests by parties to adopt a renewable integration cost adder until the values and methodology were fully explored and vetted in a public forum.[137]

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[135] R.13-12-010, *Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans* (December 19, 2014).

[136] March 26, 2014 ACR at 21-23.

[137] D.13-11-024, *Decision Conditionally Accepting 2013 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan and On-Year Supplement* (November 20, 2013) at 26-27.

In the past several months, the Commission has made significant progress in reviewing this complex topic within this proceeding. Nevertheless, more work needs to be done. Parties filed comments and reply comments on various proposals on July 2, 2014 and July 30, 2014.[138] Additional information was provided in response to the July 17, 2014 questions from the Energy Division. The proposals are summarized below.

6.3.2. Proposals by Parties

The comments by parties indicate a general consensus on several topics. Parties generally agree on what should be accounted for in a renewable integration cost adder. Importantly, a general consensus exists that integration costs include both variable and fixed costs, as follows:[139]

- Variable costs include:
  - Ancillary services costs for offsetting intra-hour variability (reg-up/down),
  - Flexible ramping capacity costs for offsetting intra-hour forecast error, and
  - Flexible ramping capacity costs for meeting hour-by-hour and multi-hour capacity needs,
- Fixed costs include: costs associated with meeting new and perhaps existing long-term flexible capacity requirements.

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[138] Calpine July 2, 2014 comments at 13; CalWEA July 2, 2014 comments at 30; LSA July 2, 2014 comments at 13; Ormat July 2, 2014 comments at 29; SDG&E July 2, 2014 comments at 10.

[139] BrightSource July 2, 2014 comments at 4; Calpine July 2, 2014 comments at 5; CalWEA July 2, 2014 comments at 19; Ormat July 2, 2014 comments at 19; PG&E July 2, 2014 comments at 2; SCE July 2, 2014 comments at 3; and SDG&E July 2, 2014 comments at 5. LSA did not provide specific recommendation, in July 2, 2014 comments.

A general consensus among parties also exists on the basic parameters for calculating a renewable integration cost adder, which are as follows:[140]

- Indirect costs associated with integrating renewables should only be included (i.e., do not include secondary benefits such as ability to hedge against fuel costs);
- The integration cost adder should be included in the LCBF methodology and accounted for on the cost side of the net market value equation;
- The integration cost adder should be developed for each major technology and also take into consideration project location;
- The integration cost adder should be based on the contract term for the project and an assumed portfolio mix (*i.e.*, 40% RPS) that is greater than 33%;[141] and
- The integration cost adders should be dependent on portfolio mix and system need and, as a result, must be updated regularly.

In addition, the comments of parties suggest three methodologies for calculating a renewable integration cost adder. These methodologies are summarized below:[142]

1. Rely on the stochastic modeling approach currently being considered in the LTPP proceeding, R.13-12-010, to calculate renewable integration cost adders through deductive production cost modeling.

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140 BrightSource July 30, 2014 reply comments at 6; LSA July 30, 2014 reply comments at 10; Ormat July 30, 2014 reply comments at 21; PG&E July 30, 2014 reply comments at 10; SDG&E July 30, 2014 reply comments at 6; SCE July 30, 2014 reply comments at 3.

141 This recommendation was made primarily because there has been no need shown for incremental flexible capacity in the most recent LTPP findings under a 33% scenario.

142 Calpine July 30, 2014 reply comments at 10 -11; CalWEA July 30, 2014 reply comments at 19-38; PG&E July 30, 2014 reply comments at 3-8; Ormat July 30, 2014 reply comments at 26-28; SDG&E July 30, 2014 reply comments at 9.

2. Rely on market based pricing for calculating costs associated with intra-hour and multi-hour variability caused by intermittent generation and production cost modeling for approximating the long-term cost of integrating incremental renewables under higher penetration levels;
   - Derive $/MWh from CAISO market cost for regulation,
   - Derive $/MWh from CAISO market from upcoming flexi-ramp product in real-time market,
   - Derive $/MWh from CAISO market from Flexible Resource Adequacy Criteria Must Offer Obligation (FRACMOO) for meeting 3-hour system net load ramps.
   - Production cost modeling could be completed by one or many types of models (E3 REFLEX model, Astrape SERVM, SCE proprietary, etc.).
3. Rely on publicly available studies for purposes of interim values until an approach is agreed upon by parties and costs have been calculated.[143]

6.3.3. Interim Approach

Of the methodologies suggested by parties, we are in a position today to only consider an interim renewable integration cost adder for the 2014 RPS solicitation and LCBF, rather than a final methodology. The approach adopted today shall remain in place until the Commission adopts a different approach, which we expect will happen in 2015. The record development for a final methodology is an on-going process and, as of today, is not sufficiently developed to provide a basis for a decision on a final methodology.[144] Key data

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[143] SCE July 30, 2014 reply comments at 2-3; PG&E July 30, 2014 reply comments at 13-14.

[144] For example, now under way in R.13-12-010 (Phase 1A) is a discussion of operating flexibility studies, which is an important factor in consideration of a final methodology.

Footnote continued on next page

points will not be available for the Commission's consideration for several more months, at the earliest. Many parties recommend an interim approach while the issue continues to be examined and refined by the Commission on an in-depth basis.[145]

We find that an interim approach is reasonable, especially in light of the strong interest expressed by both the parties and in the legislature in making progress on this issue.[146] At the same time, we recognize that an interim value may not be as accurate as the results we obtain from a more lengthy and in-depth review. For this reason, the interim approach we adopt today will remain in place only until the Commission adopts a more comprehensive approach, anticipated in 2015.

6.3.4. Interim Proposals by PG&E and CalWEA

In adopting interim values, our goal is to more closely align procurement and LCBF methodology with actual costs and benefits resulting from renewable resources. We also recognize that additional work may be needed to refine the result adopted today. We find that an integration cost adder, even if interim and in need of further refinement, will move us toward differentiating among

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R.13-12-010, *Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans* (December 19, 2014).

145 Parties suggesting that the Commission adopt interim values include IEP July 2, 2014 comments at 4; BrightSource July 2, 2014 comments at 5; Calpine July 2, 2014 comments at 6; CalWEA July 2, 2014 comments at 27; LSA July 2, 2014 comments at 12; Ormat July 2, 2014 comments at 20; PG&E, July 2, 2014 comments at 3 and 12; SCE July 2, 2014 comments at 3; and SDG&E July 2, 2014 comments at 5.

146 The legislature approved AB 2363 (Dahle, Stats. 2014, ch. 610), to impose a timeline on the Commission for consideration and adopting of an integration cost adder. This bill was chaptered on September 26, 2014.

various renewable technologies and determining the impact intermittency has on system operation and costs.

The record contains information on calculating interim values. Two parties submitted proposals for interim values, PG&E and CalWEA. In comments, SCE[147] offers support for PG&E's interim proposal. Calpine and LSA[148] offer support for CalWEA's interim proposal.[149]

CalWEA's interim integration cost adder methodology includes a short-term, medium-term, and long-term component and, in addition, it is based on the ANMV formula considered by the Commission in D.12-11-016.[150] The ANMV formula is ANMV = (E+C+S) – (P+T+G+I), where E is energy value, C is capacity value, S is ancillary services value, P is post-TOD PPA price, T is transmission cost adder, G is congestion cost adder, and I is integration cost adder. Specifically, CalWEA proposes that the following calculation and values for the short, medium, and long-term components of its proposed integration adder methodology:

- the short-term component can be calculated based on the CAISO's experience with Flexible Ramping Constraints and Flexible Ramping Products (discussed in more detail below);

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147 SCE July 30, 2014 reply comments at 4. In D.12-11-016 the Commission adopted the NMV formula, and CalWEA refers to this formula as the Adjusted Net Market Value (ANMV). D.12-11-016 described the ANMV as also including, ancillary services. The NMV did not. In addition, the "S" (or Ancillary Services) in the ANMV was not adopted in D.12-11-016 due to the lack of information.

148 LSA July 30, 2014 comments at 14; Calpine July 30, 2014 comments at 11.

149 CalWEA July 2, 2014 comments at 18.

150 CalWEA July 2, 2014 comments at 18, citing to D.12-11-016, *Decision Conditionally Accepting 2012 Renewables Portfolio Standard Procurement Plans* (November 8, 2012) at 24.

- the medium-term component will not be known in time for the 2014 solicitation cycle and, as a result, CalWEA proposes a zero value be used for the medium-term integration cost; and
- for the long-term components, CalWEA proposes a zero value for procurement aimed at achieving the 33% target in 2020.[151]

We provide more detail on how CalWEA proposes to establish the value for the short-term component, since the other two components will be valued at zero for purposes of the interim value. First, CalWEA explains that costs are a portion of total costs related to the CAISO's procurement of Flexible Ramping Product (FRP)[152] and that information on the CAISO's FRPis available on the CAISO's website.[153] CalWEA explains that, while Flexible Ramping initiative is still being finalized through a CAISO stakeholder process, the CAISO has provided proxy costs for FRP based on the costs associated with its Flexible Ramping Constraints (FRC) in its real-time market.[154] CAISO has a methodology to allocate Flexible Ramping Constraints to load and to supply sources and to fixed ramps in self-schedules. The CAISO intends to use this same method to allocate procurement of Flexible Ramping Product costs. The FRP will replace the FRC. CalWEA has extended the CAISO's allocation methodology to assign supply-related FRC costs to specific supply sources on the basis of each sources' contribution to 10 minute changes in uninstructed imbalance energy (UIE), based

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151 CalWEA July 2, 2014 comments at 30.

152 The FPR addresses the CAISO's need to maintain power balance in its real-time markets (also referred to as RTM). CalWEA July 2, 2014 comments at 20.

153 CalWEA July 2, 2014 comments at 20.

154 CalWEA July 2, 2014 comments at 20.

on the data on 10 minute changes in the UIE by supply sources in the CAISO's workpapers. CalWEA states that, to present more accurate values, the results presented by CalWEA in comments would need to be updated to include all data now available which will also reflect any update in the approach that the CAISO uses to allocate these costs among different sources of supply.[155]

Overall, we find that CalWEA's proposal merits additional consideration. However, as CalWEA acknowledges, "all of the data required is not yet available" to complete its methodology.[156] CalWEA continues to support the Commission's adoption of an integration cost adder for the 2014 RPS solicitation despite this acknowledgment.[157]

We find that CalWEA's proposal, by relying on zero value for two of its proposed components due to the unavailability of information, fails to move the issue forward sufficiently right now. Therefore, we decline to adopt CalWEA's interim proposal based on the unavailability of the needed information. We now review the other interim proposal.

PG&E's proposal consists of two components and is summarized as follows:[158]

1. The variable (or operating) integration cost is $4/MWh for wind and $3/MWh for solar. These values are based on a range of variable integration costs observed in existing

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155 CalWEA July 2, 2014 comments at 22.

156 CalWEA July 2, 2014 comments at 19.

157 CalWEA July 2, 2014 comments at 28, stating: The Commission should not allow the "perfect to be the enemy of the good" and proceed in 2014 with values that can readily be calculated using the data at hand.

158 PG&E's proposal is set forth in detail in its July 30, 2014 reply comments at 13-14. These comments are available on the Commission's website at Docket Card and R1105005.

integration studies, starting from $1.02/MWh to $19.01/MWh for wind and $1.25/MWh to $6.06/MWh for solar.[159]

2. The fixed cost component is calculated by each utility separately based on the utility's portfolio need to secure additional capacity from resources not already procured to meet its flexible and non-flexible resource adequacy requirements over the contract period. The fixed cost adder is calculated as the product of (a) and (b) below:

   (a) The monthly increase (or decrease) in flexible capacity requirement due to the increment of wind or solar being considered for the solicitation, based on the most recently adopted Commission decision on resource adequacy (commonly referred to as RA).[160] This incremental requirement is calculated based on the overall system flexible capacity requirement and then applies the percentage contribution from wind or solar. The methodology to determine both the flexible capacity requirement and the percentage contribution are defined in the California Independent System Operator's Flex-RA study.[161]

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[159] PG&E's recommendation is based on publicly-available data on integration costs for wind and solar throughout the Western Electricity Coordinating Council (WECC) region as reflected in a 2013 National Renewable Energy Laboratory (NREL) report, *A Review of Variable Generation Integration Charges*, March 2013 at http://nrel.gov/docs/fy13osti/5783.pdf.

[160] *See, for example*, the pending proposed decision issued on May 27, 2014 in R.11-10-023, *Proposed Decision Adopting Local Procurement and Flexible Capacity Obligations for 2015, and Further Refining the Resource Adequacy Program.* If approved by the Commission, this decision would reflect the most recent values.

[161] *See* CAISO's 2014 Flexibility Needs Assessment (http://www.caiso.com/Documents/Final_2014_FlexCapacityNeedsAssessment.pdf).

(b) The projected monthly price (which can be zero or positive) for flexible RA, which is the same parameter used in calculation of capacity benefits.[162]

We find that PG&E presents a reasonable approach for use on an interim basis. We further find that this interim approach will enable procurement costs to more accurately reflect costs resulting from renewable resources. PG&E's approach presents values that are, perhaps, conservative and we acknowledge that additional refinement is needed.[163] However, we are confident that we are moving toward a more accurate reflection of costs even if these costs will need to be updated, perhaps even increased, as the framework to determine more exact values moves forward.

6.3.5. Next Steps – Final Methodology

Setting forth the next procedural steps for this complex issue will expedite the Commission's consideration of renewable integration cost adder.

While we adopt an interim valuation methodology in this proceeding, the process going forward to consider comprehensive methodology will be in coordination the 2014 LTPP proceeding (R.13-12-010)[164] and may involve the

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162 PG&E provides an example, for illustration purposes only, in its July 30, 2014 reply comments at 14. We reproduce this example for explanatory purposes only: "For illustration purpose only, if the monthly cost of flexible capacity in the month of November of 2020 is $2/kw-month and the increase due to an increment of wind is 1% of installed wind capacity, and 40% of installed solar capacity, in the corresponding fixed integration costs for this month would be $0.10/MWh for wind and $3.60/MWh for solar, assuming a 30% capacity factor for each technology."

163 LSA November 10, 2014 comments at 6, stating that deficiencies continue to exist in the interim approach, such as the lack of necessary information, but LSA supports adoption of the interim value.

164 R.13-12-010, *Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans* (December 19, 2014). PG&E July 30, 2014 reply comments at 8-9, Ormat July 2, 2014 comments at 27; UCS July 2, 2014 comments at 5.

need to coordinate with other proceedings. The record of R.13-12-010 encompasses all electric procurement. By coordinating with R.13-12-010, and the associated record data in that proceeding, the Commission will be positioned to take the next steps toward adopting a final methodology.

The process to consider a final methodology may include hearings or workshops to be scheduled as soon as practicable.[165] Additional written comments may also be requested. After a general methodology is considered in this proceeding in coordination with R.13-12-010 and any other relevant proceedings, the Commission may place the issues specific to renewable procurement into the RPS proceeding.

Accordingly, in the final 2014 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E and SCE shall incorporate an interim integration cost adder for the 2014 RPS solicitation consistent with the above. PG&E and SCE shall update their LCBF methodologies to include a description of how they will calculate integration cost adders based on the adopted interim methodology. The description should clearly describe the methodology for calculating the adder, the components of the adder, the source for any variables used to calculate the adder and its components, and how the adder will be applied to a bid in its evaluation.

These interim values shall also be integrated within the LCBF process for 2014. A final methodology will be considered in this proceeding and in coordination with R.13-12-010 and any other relevant proceedings in the future.

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[165] SDG&E July 30, 2014 reply comments at 8.

Until a final methodology is adopted, the Commission authorizes minor changes to be made to this methodology by ruling.

7. RPS Procurement Reform – April 2014 Energy Division Proposal

In this decision, we adopt some aspects of the Energy Division proposal for reform of the RPS procurement process. The Energy Division proposal was attached to an ALJ ruling dated April 8, 2014.[166] Specifically, we adopt the following: (1) utilities must include specific data in filings with the Commission related to RPS contracts, (2) utilities must adhere to a definitive timeline of 100 days when seeking approval of RPS shortlists of bid; (3) utilities must adhere to a definitive timeline of 90 days when seeking approval of RPS contracts; (4) utilities are authorized to seek approval for short-term contracts (less than 5 years) through a Tier 1 Advice Letter; (5) the Commission will apply a uniform standard of review to all contracts seeking approval within the RPS Program; and (6) we confirm the Energy Division's authority to request information from Independent Evaluators. We decline other aspects of the proposal. We review the entire proposal below.

7.1. Background

On April 5, 2012, the assigned Commissioner issued a Ruling with several new proposals related to the Commission's review of renewable generation procured by utilities as part of the state's RPS program. On October 5, 2012, the assigned Commissioner issued a second Ruling that offered additional proposals

[166] *Administrative Law Judge's Ruling (1) Issuing Staff Proposal to Reform Procurement Review Process for the Renewable Portfolio Standard Program, (2) Setting Comment Dates, and (3) Entering Staff Proposal into the Record* (April 8, 2014).

to refine the Commission's review process for generation procured under the state's RPS program. Parties filed comments and, on January 22, 2013, the Energy Division held a workshop to discuss each of the procurement reform proposals in the Assigned Commissioner's Rulings. In response to comments, the Energy Division prepared a revised proposal, referred to as the *April 2014 RPS Procurement Reform Staff Proposal* (Energy Division Proposal). This proposal was attached to an ALJ Ruling dated April 8, 2014. Parties filed comments on this proposal on May 7, 2014 and May 28, 2014.

7.2. Goals of RPS Procurement Reform

As described in the April 8, 2014 ALJ Ruling, the goals of the procurement reform effort are to streamline the RPS contract review process, increase the transparency of the Commission's review of RPS procurement, establish clear standards for the RPS procurement review process, issue Commission determinations on contract reasonableness on a defined timeline, and, generally, support market certainty in RPS procurement. We review below the Energy Division Proposal.

7.3. Data Adequacy Requirements – General and Environmental

In this decision, we adopt the Energy Division's proposal for data adequacy requirements but refrain, with one exception, from adopting the Energy Division's proposal for specific data requirements related to the environmental data as we find these additional requirements not necessary at this time. We adopt the Energy Division's proposal to require the utilities to provide the Commission with a Geographic Information System (GIS) file of the project boundaries and associated gen-tie for all projects that currently have an

RPS PPA and for all future RPS bids submitted to an annual RPS solicitation or other RPS procurement program.

The Energy Division proposed that a general data adequacy requirement apply to all information submitted to the Commission by an IOU to ensure timely and efficient review.[167] In addition, the Energy Division proposes specific environmental data adequacy requirements be adopted as part of in the procurement review process.[168]

No parties offer comments on the proposed general data adequacy requirements. Most parties oppose the specific environmental data adequacy requirement. IEP, LSA and PG&E state that the existing environmental permitting process in California is comprehensive and, in addition, the environmental and cultural impacts of each project are well vetted by existing laws.[169] NextEra and LSA comment that, if the goal of the Energy Division's proposal is to ensure higher project viability, the CAISO interconnection process now requires increased development security which should provide this purpose.[170] Some parties state that the proposed additional environmental information could provide project opponents with a basis to encourage litigation at the Commission or before state and federal courts and, as a result, negatively impact the viability of projects.[171] Others suggest that if any Commission

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167 April 8, 2014 ALJ Ruling at Attachment (Energy Division Proposal) Section 4.1 at 8.

168 April 8, 2014 ALJ Ruling at Attachment (Energy Division Proposal) Section 4.1 at 9-10.

169 NextEra January 30, 2014 comments at 3; IEP January 30 2014 comments at 3; LSA January 30, comments at 4; PG&E January 30, 2014 comments at 6-7.

170 NextEra January 30, 2014 comments at 4; LSA January 30, 2014 comments at 4.

171 IEP January 30, 2014 comments at 3; CalWEA January 30, 2014 comments at 5; SDG&E January 30, 2014 comments at 4; PG&E January 30, 2014 comments at 6.

decisions are based on the proposed additional data, it could, essentially, pre-judge the permitting process, a process that falls outside the scope of the Commission's review.[172]

We find that the Energy Division's proposal on general data adequacy is reasonable as this aspect of the proposal serves to strengthen the data requirements already in place. We adopt, as set forth below, most aspects of this proposal. With regard to the environmental data adequacy requirements, we agree with the Energy Division's concerns of due diligence and project viability. We also agree with parties that environmental aspects of projects are vetted by existing laws. Therefore, we refrain from adopting the proposed environmental data adequacy requirements, with one exception. We adopt the Energy Division's proposal to require the utilities to provide the Commission with a GIS file of the project boundaries and associated gen-tie for all projects that currently have an RPS PPA and for all future RPS bids submitted to an annual RPS solicitations or RPS procurement program.[173] This information will assist the Commission with overall procurement planning related to the RPS Program. The Director of the Energy Division is directed to provide PG&E, SCE, and SDG&E with the details on how to comply with this requirement. Responses must be provided to the Director of the Energy Division.

Accordingly, PG&E, SCE and SDG&E shall comply with the adopted general data adequacy and GIS file requirement herein. These requirements are as follows: (1) the shortlist advice letter template must be complete; (2) the

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[172] CalWEA January 30, 2014 comments at 3; LSA January 30, 2014 comments at 6; PG&E January 30, 2014 comments at 4.

[173] Joint Conservation Parties November 10, 2014 comments at 2-3.

contract/power purchase agreement advice letter template must be complete; (3) all required Excel/Word workspapers must be complete; and (4) a GIS file of the project boundaries and associated gen-tie for all projects that currently have an RPS PPA and for all future RPS bids submitted to annual RPS solicitations or RPS procurement programs. The Commission will not act to approve a request unless all data is complete or otherwise sufficiently accounted for.

7.4. Standards of Review for IOU Shortlists

In today's decision, we adopt, in part, the Energy Division's proposal to streamline the Commission's review of the IOUs' advice letter filings seeking approval of the IOUs' shortlists of bids (following the close of the annual solicitation). Specifically, we retain the requirement that IOUs seek approval of these shortlists through a Tier 2 Advice Letter filing, and we adopt the additional requirement that these Tier 2 Advice Letters with the shortlists be filed 100 days after the close of the solicitation.

The Energy Division proposed that the Commission require IOUs to file their shortlists of bids by a Tier 3 advice letter (which requires final disposition by a Commission Resolution) rather than the existing procedure, a Tier 2 advice letter (which provides for an automatic effective date or final disposition by Commission Resolution). The Energy Division Proposal also suggested a deadline for this filing, that the advice letter be filed within 60 days after close of the annual RPS solicitation.[174] No specified timeline for filing this advice letter currently exists. Instead, each year a file date is adopted by the Commission in its decision approving of the annual RPS Procurement Plans.

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[174] April 8, 2014 ALJ Ruling at Attachment (Energy Division Proposal), Section 4.2 at 10.

Regarding the Energy Division's proposal to rely on a Tier 3 Advice Letter, several parties support the proposal but with modifications. For example, one party offers support for the concept but not the quantity of information being requested.[175] Most parties oppose changing the requirement to a Tier 3 Advice Letter. Parties question how replacing the more expedited Tier 2 Advice Letter process with the more in-depth review related to the Tier 3 Advice Letter process assists in furthering the Commission's objective of streamlining the review process.[176] Other parties point out that, under the Energy Division's proposal, the RPS procurement process would include two Tier 3 Advice Letter review processes (one for the shortlists and another for each power purchase agreement), and parties express concern that the overall process will become unduly burdensome and result in greater delays.[177] Parties also comment that 60 days is not long enough to submit the shortlist via an advice letter filing.[178] Instead, parties suggest that the Commission adopt a deadline of 100 days or even 120 days for seeking approval of the shortlist via an advice letter filing.[179]

We find that the Tier 2 Advice Letter process provides the appropriate level of oversight and that increasing the review process to, instead include a Tier 3 Advice Letter process contradicts to our goal of streamlining the RPS

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[175] GPI January 30, 2014 comment at 1-2.

[176] NextEra January 30, 2014 comments at 5; LSA January 30, 2014 comments at-8; CEERT January 30, 2014 comments at 11; IEP January 30, 2014 comments at 4; PG&E January 30, 2014 comments at 9; SCE January 30, 2014 comments at 7; Iberdrola January 30, 2014 comments at 4; CalWEA January 30, 2014 comments at 6.

[177] Iberdrola January 30, 2014 comments at 4; CalWEA January 30, 2014 comments at 6.

[178] NextEra January 30, 2014 comments at 5; LSA January 30, 2014 comments at 8.

[179] SDG&E January 30, 2014 at 8; PG&E January 30, 2014 comments at 8-10; and SCE January 30, 2014 comments at 9.

procurement review process. The Tier 2 Advice Letter process will remain in its current format, no additional information is required. We further find that, consistent with the Energy Division Proposal, adopting a deadline for the filing of this Tier 2 Advice Letter for approval of the shortlist will function to create more structure and predictability around the process, and, in this manner, prevent unreasonable delay. We find the deadline of 100 days after the end of the solicitation reasonable.

The Energy Division Proposal included additional suggestions, such as that the utilities publicly disclose and rank in their shortlist advice letter filings the bids and that the utilities provide renewable net short and LCBF analysis for each bid.[180] The Energy Division also suggested that utilities be prohibited from entering into contracts until after the Commission approves the shortlist.[181]

We do not adopt these requirements. We acknowledge that these proposals may offer some additional Commission oversight of the shortlist bids. However, we are concerned that the proposals ultimately create layers of review by Commission that are duplicative. We are also concerned that the proposals result in the Commission being overly involved in the contracting process. Requiring public disclosure of bid ranking and placing restriction on when parties can finalize contracts places the Commission in a position of potentially unreasonably interfering with the contracting process. The parties are in a better position than the Commission to determine the appropriate time to finalize a contract and the type of information needed to make informed decisions.

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180 April 8, 2014 ALJ Ruling at Attachment (Energy Division Proposal), Section 4.2 at 11-12.

181 April 8, 2014 ALJ Ruling at Attachment (Energy Division Proposal), Section 4.2 at 12.

Accordingly, PG&E, SCE, and SDG&E shall revise their RPS protocols, as needed, to account for filing their bid shortlists 100 days after the close of their RPS solicitations. All requests for extension must be made to the Commission's Executive Director pursuant to Rule 16.6 of the Rules of Practice and Procedure.

7.5. Establish Date Certain for Contract Execution and Submission for Commission Approval

In this decision, we adopt the Energy Division's proposal to establish a date certain before which the utilities must file advice letters or other appropriate filing seeking Commission approval of executed RPS contracts. A reasonable timeline will function to create more structure and predictability around the Commission review process, and, in this manner, encourage timely decision-making based on current market information.

Currently, the utilities must execute an RPS contracts within 12 months of the date the shortlist is submitted to the Commission for approval.[182] Then, the utilities file advice letters seeking Commission approval of the finalized RPS contract via a Tier 3 Advice Letter filing or other appropriate means. No definitive timeline applies to the filing of the advice letter or other appropriate filings. The Energy Division proposed that the Commission adopt a definitive timeline for utilities to both execute the contracts and also to file these Tier 3 Advice Letters or other appropriate filing so that the process is not completely open ended and completed within a reasonable amount of time. More

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[182] D.12-11-016, *Decision Conditionally Accepting 2012 Renewables Portfolio Standard Procurement Plans* (November 8, 2012) at 34-36, stating, "[B]ids shortlisted by PG&E and SDG&E shall be executed, if at all, within 12 months from the date that the utilities submit final shortlists to the Commission for approval…While SCE will not hold a 2012 solicitation, this requirement will apply to future solicitations until otherwise directed by the Commission."

specifically, the Energy Division proposed that the Commission require: (1) IOUs to execute RPS contracts within 1 year after the Commission approves the IOUs' shortlist and, in addition; (2) require utilities to file an advice letter or other appropriate filing seeking approval of any executed RPS contracts within 90 days from the date of execution.[183]

The Energy Division stated that these timelines are needed because the RPS market and IOUs' procurement needs are subject to change, and, as a result, the merits of an IOU's RPS need analysis is often stale before a utility executes the contract or seeks approval of the contract.[184]

Parties generally oppose these proposals. Parties state that a firm expiration date of 1 year for the contract negotiation period could result in the delaying, rather than streamlining, of the execution of contracts because the deadlines impose an unnecessary burden on bidders and possibly provide leverage to utilities.[185] Parties add that this could also ultimately result in disadvantaging ratepayers through higher costs.[186]

A few parties offer support for imposing the definitive timelines suggested by the Energy Division. These parties state that benefits exist in setting up a process that enables the Commission to make decisions based on current market data, rather than stale information.[187]

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183 April 8, 2014 ALJ Ruling at Attachment (Energy Division Proposal), Section 4.3 at 13-14.

184 April 8, 2014 ALJ Ruling at Attachment (Energy Division Proposal), Section 4.3 at 13.

185 CEERT January 30, 2014 comments at 12-13; Iberdrola January 30, 2014 comments at 4; IEP January 30, 2014 comments at 5.

186 CEERT January 30, 2014 comments at 12-13; Iberdrola January 30, 2014 comments at 4; IEP January 30, 2014 comments at 5.

187 ORA January 30, 2014 comments at 3; SDG&E January 30, 2014 comments at 8.

We find that a 12-month timeline for contract negotiations may result in undue and unknown pressures on the contracting parties, which may even result in increased ratepayer costs. In addition, the proposal appears to overlap with our existing rule, adopted in D.12-11-016, for the shortlist to expire within 12 months. As a result, we refrain from adopting this recommendation. We agree, however, with the goal of the Energy Division to enable the Commission to evaluate contracts based on substantially the same market conditions and RPS need evaluation as was relevant to the contracting parties in making their decision to enter into and execute the contract.[188] Therefore, in an effort to impose some time limitations on the Commission's approval process, we find that the requirement to file an advice letter or other appropriate filings seeking contract approval within 90 days from the date of execution of the contract is reasonable.

Accordingly, within 90 days from the date of execution of RPS contracts, PG&E, SCE, and SDG&E shall file with the Commission seeking approval of that contract. This requirement applies to all future RPS solicitations unless otherwise stated by the Commission.

7.6. Expedited Commission Review of RPS Purchase and Sale Contracts – Term of Less than 5 Years

In today's decision, we modify the current process for utilities to seek approval of a short-term contract (under 5 years) by authorizing the use of a Tier 1 Advice Letter, rather than a Tier 3 Advice Letter.

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[188] April 8, 2014 ALJ Ruling at Attachment (Energy Division Proposal), Section 4.3 at 13.

Under the Commission's conventional procurement process (non-RPS procurement), contracts with terms greater than or equal to five years in duration must be submitted to the Commission via application for pre-approval of cost recovery.[189] Final cost recovery is authorized by a Commission decision. The Commission approves short-term convention-fuel contracts (less than five years) that meet certain standards through the Quarterly Compliance Report.. By contrast, under the RPS program, utilities seek pre-approval for cost recovery for all RPS contracts, regardless of contract term or portfolio content category (with some exceptions), by a Tier 3 Advice Letter.[190]

The Energy Division proposed to streamline the approval process for short-term RPS contracts (less than five years) by changing a number of elements of the existing review process. First, utilities would be required to file and obtain Commission approval of another pro-forma contract for short-term transactions (less than five years).[191] This short-term pro form contract would be in addition to the existing requirement that utilities file a pro form contract for general purchases and sale. The utilities would be required to file this additional contract with their annual procurement plan filing. The Commission, in turn, would review and approve this short-term contract. Upon receipt of

[189] D.04-12-048, *Opinion Adopting Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company's Long-Term Procurement Plans* (December 20, 2004).

[190] Existing exceptions include: Feed-In Tariff contracts, Renewable Auction Mechanism, the current RPS program expedited approval process approved set forth in D.09-06-050, and RPS contracts submitted in Applications. The expedited approval process in D.09-06-050 for short-term RPS contracts (terms of five years or less) has rarely been used and the Commission has never approved an RPS contract under this process.

[191] April 8, 2014 ALJ Ruling at Attachment (Energy Division Proposal), Section 4.4 at 15-16.

Commission approval of this pro forma contract, any transaction relying on this pro forma contract would be eligible for cost recovery through ERRA. The Energy Division proposed that in addition to the ERRA process, the utilities also be required to file a Tier 1 Advice Letter on a quarterly basis and include all contracts relevant to that time period, rather than file individual advice letters with a single contract. It is unclear from the proposal whether the Energy Division proposed the use of just a pro form contract or also suggested the use of a standard contract.

Parties generally support this proposal.[192] However, parties also state that the standard contract provision should be eliminated because it would limit the ability to balance counterparty risk through a negotiated contract.[193] Parties appear to prefer a pro form contract.[194] Other parties seek to include contracts involving repowers or re-contracting with existing facilities on the basis that these contracts are lower risk.[195]

We adopt certain aspects of the proposal. We agree that a streamlined process for contracts under five years is appropriate. For this reason, we permit utilities to seek approval of contracts less than five years by a Tier 1 Advice Letter, rather than the existing Tier 3 Advice Letter requirement. We do not adopt the Energy Division's proposal to rely on quarterly Tier 1 advice letter compliance filings. The utilities must file a separate advice letter for each contract

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[192] CEERT January 30, 2014 comments at 14-16;

[193] PG&E January 30, 2014 comments at 12; SCE January 30, 2014 comments at 12; SDG&E January 30, 2014 comments at 9.

[194] SCE January 30, 2014 comments at 12; SDG&E January 30, 2014 comments at 9-10.

[195] NextEra January 30, 2014 comments at 7-8;

to request approval and cost recovery. While quarterly filings may reduce the number of filings, we prefer to have more current information than permitted under a quarterly filing requirement. We further find that adoption of a separate pro forma contract, but not a separate standard contract, for these short-term contracts will benefit the parties and the ratepayers by providing additional structure for the negotiation process. Consistent with current practice in the annual RPS solicitation, parties are permitted to rely on a pro forma contract filed and approved by the Commission as part of the annual RPS Procurement Plans. Parties may negotiate the contract as needed. We seek to avoid unnecessary involvement or control of the RPS contracting and negotiation process to avoid having the Commission micromanaging and unduly restraining the contracting process through a standard contract. We refrain from adopting any of the other requirements for these advice letters which may be identified in the Energy Division proposal, but authorize the Energy Division to revise its RPS Advice Letter Template, as needed, to accommodate this change in process.[196] We also deny requests to include existing but expiring contracts within this expedited procedure until we have more evidence that all these contracts, as suggested by NextEra, are lower risk and less costly. This process supersedes the so-called *fast track* RPS contract approval process adopted in D.09.06-050.[197]

Accordingly, PG&E, SCE, and SDG&E are authorized to seek Commission approval of short-term RPS sales and purchase contracts (5 years of less) through

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[196] April 8, 2014 ALJ Ruling at Attachment (Energy Division Proposal), Section 4.4 at 16-17.

[197] D.09-06-050, *Decision Establishing Price Benchmarks and Contract Review Processes for Short-Term and Bilateral Procurement Contracts for Compliance with the California Renewables Portfolio Standard* (June 18, 2009).

a Tier 1 Advice Letter. Each sale and purchase contract shall be filed in a separate advice letter. PG&E, SCE, and SDG&E shall not rely on the *fast track* process approved in D.09-06-050. The Energy Division is authorized to modify the RPS Advice Letter Template as necessary to accommodate this change. PG&E, SCE, and SDG&E shall provide a separate pro forma contract for short-term transactions with their annual RPS Plans.

7.7. Commission Review of Power Purchase Agreements, Bilateral Contracts, Contract Amendments, and Contracts for Renewable Energy Credits

In today's decision, we adopt, in part, the Energy Division proposals to establish guidelines for our review of transactions entered into between IOUs and sellers/buyers within the RPS Program. We adopt the Energy Division's proposal to rely, at a minimum, on specific elements, referred to Standards of Review, in its evaluation of the reasonableness of these transactions. We clarify, however, that our review process is fluid and may change based on market conditions. Beyond adopting Standards of Review (also referred to as SOR), we refrain from adopting further aspects of this proposal. The elements we adopt are set forth below.

The Energy Division proposed to establish rules to improve the process for Commission's review of RPS power purchase agreements submitted by Tier 3 Advice Letter.[198] The existing review process is referred to, generally, as the RPS Standards of Review.[199] Under the existing RPS Standards of Review, the Commission reviews most proposed RPS power purchase agreements submitted

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[198] April 8, 2014 ALJ Ruling at Attachment (Energy Division Proposal), Section 4.5 at 18-30.

[199] April 8, 2014 ALJ Ruling at Attachment (Energy Division Proposal), Section 4.5 at 18-30.

by an IOU via a Tier 3 Advice Letter based on the following criteria: (1) consistency with the approved RPS procurement plans, including approved LCBF methodologies; (2) consistency the existing Commission decisions; (3) cost and value reasonableness; and (4) viability relative to the IOU's other RPS procurement opportunities.[200]

The Energy Division's proposal for improving the Standards of Review is summarized in the following excerpt:

> The proposals set forth below (subsections A through E) focus on evaluating five different types of power purchase agreements: (A) contracts from an RPS solicitation; (B) bilaterally negotiated contracts; (C) contract amendments and/or amended and restated contracts; (D) contracts that do not meet SOR identified in the first three categories, contracts for generation from a technology that has not been commercially proven, contracts representing a significant portion [footnote omitted] of an IOU's portfolio; and (E) Renewable Energy Credits. For the first three types of PPAs (subsections A-C), the following SOR criteria are proposed for evaluating an RPS power purchase agreement: (1) portfolio compliance need and procurement authorization, (2) price reasonableness, (3) project value, (4) project viability, (5) consistency with Commission decisions, rules, and laws, (6) data adequacy, and (7) conformance the expenditure limitation upon issuance with the decision on cost containment.
>
> Staff proposes that if the Commission finds that a contract is consistent with the SOR, the contract may be approved without modification. If the proposed contract does not comply with the SOR, the advice letter may be rejected by the Commission and the IOU may request Commission approval by application (*see* Section D for SOR to be used for these

[200] April 8, 2014 ALJ Ruling at Attachment (Energy Division Proposal), Section 4.5 at 18.

types of applications). All SOR requirements are described in further detail below in Tables 2 through 5.[201]

A number of parties oppose the Energy Division's proposal regarding Standards of Review on the basis that the proposal fails to justify the need for a change.[202] ORA supports the proposal on the basis that ratepayers need additional protection.[203]

We find it is reasonable to adopt uniform Standards of Review for all RPS transactions. We do not adopt the Standards of Review proposed by Energy Division. Instead, we the standard of review will be uniform across all transaction included in the Energy Division proposal. Uniformity will support administrative efficiency and transparency. In addition, we clarify that *contract amendments and/or amended and restated contracts* does not include changes that are minor or non-material.[204] The Standards of Review for the noted transactions will consist of the following:

Standard of Review for all RPS Transactions

Review Element	
1. Need Authorization (GWh)	The Commission evaluates whether generation quantity is consistent with RPS net short and the IOU's most recent Commission-approved RPS procurement plan.

201 April 8, 2014 ALJ Ruling at Attachment (Energy Division Proposal), Section 4.5 at 18-19.

202 UCS January 30, 2014 comments at 4; CEERT January 30, 2014 comments at 17; Iberdrola January 30, 2014 comments at 5; LSA January 30, 2014 comments at 9-10; IEP January 30, 2014 comments at 9; PG&E January 30, 2014 comments 15; SCE January 30, 2014 comments at 21.

203 ORA January 30, 2014 comments at 4.

204 CalWEA November 10, 2014 at 2-3.

Review Element	
2. Net Market Value, Contract Price, and Project Viability	The reasonableness of a contract's net market value, price, and viability will be assessed relative to: (1) the shortlisted bids from the annual RPS solicitation from which the subject contract originated; and (2) all comparable PPAs executed by the IOU in the 12 months prior to subject contract's date of execution. For unbundled renewable energy credit contracts: contract price will be assessed relative to: (1) shortlisted unbundled REC bids from the most recent annual RPS solicitation and REC solicitation and (2) all unbundled REC contracts that executed by the IOU in the 12 months prior to subject contract's date of execution.
3. Consistency with Commission Decisions	The Commission evaluates whether the transaction is consistent with all relevant Commission decisions, including, but not limited to, D.02-08-071, D.04-07-029, D.06-05-039, D.07-01-039, D.08-04-009, D.08-08-028, and D.10-03-021, as modified by D.11-01-025, D.11-12-020, and D.11-12-052.
4.Update Information	The Commission directs the IOUs to provide the following updated values as part of their filing seeking approval of the RPS transaction: (1) renewable net short; (2) the project's net market value, and (3) the project's viability score.

Review Element	
5.Monthly Information Updates	For contracts filed with the Commission, the IOUs shall provide monthly updates to the Energy Division on project development milestones, potential compliance delays, updated project viability scores, an updated assessment of project risk an updated assessment of portfolio net short. The Energy Division is authorized to determine the format that this information is provided and should use existing processes to the extent possible.

Accordingly, PG&E, SCE, and SDG&E should seek to comply with the above noted Standards of Review when seeking approval of transactions within the RPS Program. The Energy Division is authorized to request the utilities to provide this information in a specific format and to modify these requirements to ensure full and complete review of RPS transactions.

7.8. Independent Evaluator Reports on the Shortlist of Bids filed by IOUs

In this decision, we adopt, in part, the Energy Division's proposal regarding Independent Evaluator Reports. We decline to adopt the Energy Division's proposal that the Commission require the Independent Evaluator's Reports to include a final conclusion for the Commission to either approve or reject the IOU's (1) shortlist of bids and (2) final contract.

In D.06-05-039, the Commission directed Independent Evaluators to review and prepare a report on each IOU's RPS solicitation, evaluation, and selection process. Currently, the IOUs include the Independent Evaluator's

Report in all advice letters or applications requesting Commission approval of an RPS contract.[205] Independent Evaluators are hired and work under contract by PG&E, SCE, and SDG&E. This hiring and contract process is overseen by the Energy Division and paid for by ratepayers.[206] To date, the Commission has not adopted any specific review and reporting guidelines for Independent Evaluators. However, in the past, the Energy Division has provided Independent Evaluators with reporting templates with the information that must be included in the reports regarding the RPS solicitations and contracts.

The Energy Division proposes that the Commission adopt specific reporting guidelines for Independent Evaluators rather than rely on informal requests by the Energy Division.[207] The proposal is as follows:

> The IE [Independent Evaluator] must provide a definitive recommendation in the IE Report to the Commission regarding whether the IOU conducted its evaluation of bids in a fair and reasonable manner and if the shortlist [and final contracts] should either be "approved" or "rejected." This recommendation must be justified based on an evaluation of the shortlist based on: (1) reasonableness and accuracy of LCBF methodology, (2) price and value of projects shortlisted, (3) viability of projects on shortlist, (4) approved renewable net short, and (5) any relevant safety considerations.[208]

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[205] D.06-05-039, *Opinion Conditionally Approving Procurement Plans for 2006 RPS Solicitations, Addressing TOD Benchmarking Methodology and Closing Proceeding* (May 25, 2006) at 46.

[206] D.06-05-039, *Opinion Conditionally Approving Procurement Plans for 2006 RPS Solicitations, Addressing TOD Benchmarking Methodology and Closing Proceeding* (May 25, 2006) at 46.

[207] April 8, 2014 ALJ Ruling at Attachment (Energy Division Proposal), Section 4.7 at 33.

[208] April 8, 2014 ALJ Ruling at Attachment (Energy Division Proposal), Section 4.7 at 33.

Party comments are few on these aspects of the Energy Division's proposal.[209] CalWEA is generally supportive of specific aspects of the proposal, such as modifications to the reporting template used by Independent Evaluator.[210] Other parties state that those aspects of the proposal suggesting that the Independent Evaluator provide a final conclusion would be duplicative and unnecessary.[211]

We find that the Energy Division's proposal to include a final conclusion on whether the Commission should approve or reject the IOU's shortlists and contracts as part of the Independent Evaluator's Report is unnecessary. The purpose of these reports is to assist the Commission in making a final decision. It is unnecessary, therefore, for the Independent Evaluator to include, essentially, what is a final decision. However, to further assist the Commission in its decision-making process, we direct the Energy Division to continue its role of refining the elements in these reports on an on-going basis to ensure that the Independent Evaluator Reports provide the Commission with useful information that reflects the changing renewable energy markets.

Accordingly, the Energy Division shall continue its role of refining the elements of the Independent Evaluator Reports on an on-going basis to ensure that the Independent Evaluator Reports provide useful information that reflects the changing renewable energy markets. The Energy Division, at its discretion, may direct Independent Evaluators to include the following in their reports: (1) reasonableness and accuracy of LCBF methodology; (2) reasonableness of

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209 CalWEA January 30, 2014 comments; CEERT January 30, 2014 comments.

210 CalWEA January 30, 2014 comments at 15.

211 CEERT January 30, 2014 comments at 21.

price and value of projects shortlisted, (3) viability of projects on shortlist; (4) approved renewable net short; and (5) any relevant safety considerations.

8. Renewable Auction Mechanism – The Commission Revisits RAM

A comprehensive review of RAM is appropriate now because the Commission's initial capacity authorizations in D.10-12-048, as modified,[212] are mostly under contract and the IOUs have held all of the RAM auctions authorized by the Commission. In short, the auction process, as authorized by the Commission in D.10-12-048, has ended.[213]

Recognizing that the end of the auction process was approaching, the assigned Commissioner's September 12, 2012 Scoping Memo identified the review of RAM as an issue in the scope of this proceeding.[214] Then, on December 31, 2013, the ALJ issued a ruling to initiate the Commission's review of RAM. The December 31, 2013 ALJ Ruling sought comments on whether the auction process should continue under its original objective or whether benefits

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[212] On December 16, 2010, the Commission created and adopted the Renewable Auction Mechanism Program in D.10-12-048. The Commission revised the program elements in CPUC Resolutions E-4414 (August 18, 2011), CPUC Resolution E-4489 (April –9, 2012), CPUC Resolution E-4546 (November 8, 2012), and CPUC Resolution E-4582 (May 9, 2013).

[213] The Commission initially authorized 1,000 MW of capacity for the program. D.10-12-048 at 29. The Commission subsequently increased the initial 1,000 MW capacity authorization in D.12-02-002 (which authorized the transfer of 74 MW of capacity from SDG&E's PV Program to RAM), D.12-02-035 (which authorized the transfer of 225 MW of capacity from SCE's PV Program to RAM), and D.13-05-033 (which authorized the transfer of 31 MW of capacity from the UOG portion of SCE's PV Program to RAM).

[214] September 12, 2012, *Amended Scoping Memo and Ruling of the Assigned Commissioner* at 4. Later in this proceeding, on January 13, 2014, the assigned Commission issued another Scoping Memo which confirms that the review of the Renewable Auction Mechanism continued to be an issue in the scope of this proceeding. *See*, January 13, 2014 *Third Amended Scoping Memo and Ruling of Assigned Commissioner* (January 13, 2014) at 2.

exist in continuing the process with different objectives to potentially reflect the evolving renewable energy market for smaller projects.

The December 31, 2013 ALJ Ruling included an analysis by the Energy Division (Energy Division Analysis) seeking comments from parties on the effectiveness of the existing program components, such as project size restriction, predetermined commercial operation dates, standard contract provisions, eligibility, viability screens, and other terms and conditions.[215]

The details of RAM are found in D.10-12-048. Two of the key components of RAM included the requirement that utilities procure small (3 MW to 20 MW)[216] renewable distributed generation[217] and that PG&E, SCE, and SDG&E each hold four auctions over two years to accomplish this procurement.[218] In Resolution E-4582 (May 9, 2013), the Commission authorized PG&E, SCE, and SDG&E to each hold a fifth RAM auction and directed the utilities to hold this action in a manner that permitted the auction to close no later than June 27, 2014. Under the D.10-12-048 RAM process, IOUs conducted auctions and selected projects in order of least costly first, up to program capacity limit. IOUs were

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[215] December 31, 2013 ALJ Ruling at Attachment A (Energy Division Summary & Questions on Future of RAM).

[216] D.12-05-035, *Decision Revising Feed-In Tariff Program, Implementing Amendments to Public Utilities Code Section 399.20* (May 24, 2012), modified the minimum project size for RAM to greater than 3 MW in an effort to further distinguish the RAM auctions and the Feed-In Tariff Program.

[217] The term *distributed generation* was not defined in D.10-12-048.

[218] D.10-12-048 at 30. The capacity authorized by the Commission was shared between the three IOUs in a manner similar to the Feed-In Tariff Program implemented by the Commission pursuant to AB 1969 (Yee, Stats. 2006, ch. 731) in D.07-07-027, *Opinion Adopting Tariffs and Standard Contracts for Water, Wastewater and Other Customers to Sell Electricity Generated from RPS-Eligible Renewable Resources to Electrical Corporations* (July 26, 2007) at 9.

required to procure from product categories: peaking, non-peaking, and baseload. Procurement targets for the RAM 5 solicitation were 102.8 MW for PG&E, 71.9 MW for SDG&E, and 290 MW for SCE. Sub-targets existed for each product category.

The purpose of RAM, as adopted in D.10-12-048, was straightforward. The Commission adopted RAM to create a simplified market based procurement process for smaller RPS generation projects, between >3 MW and 20 MW, for the purpose of promoting competition within this smaller market segment. RAM was also expected to contribute to near term statutory RPS procurement deficits of PG&E, SCE, and SDG&E.[219]

We first review whether benefits exist in continuing RAM and, if so, whether RAM should continue under its original objective or different objectives to potentially reflect the evolving renewable energy market for smaller projects. We then explore various alternatives to reauthorize RAM to meet current market demand. Finally, we adopt a new structure for RAM and provide details on the components of this new process.

8.1. Options Moving Forward

The Energy Division Analysis presented various options for how the Commission could address RAM in the future, including: (1) maintaining the status quo, i.e., authorize additional capacity and direct the utilities to hold more auctions; (2) authoring one additional auction, a RAM 6, to address any remaining capacity; and (3) directing the IOUs use RAM as an option procurement tool with a flexible RAM structure.

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[219] D.10-12-048 at 2.

To provide a framework for reviewing these options, the Energy Division Analysis notes that, in the first four RAM auctions held by PG&E, SCE, and SDG&E, the Commission approved a total of 74 RAM contracts representing 1,061 MW of renewable generation.[220] Notably, the total capacity of the offers to bid into the first, second, and third RAM auctions was approximately 10 times larger than the allocated capacity into each auction.[221] On this basis, the Energy Division Analysis concludes that the response to the RAM auctions was robust.[222] Additionally, the Energy Division concludes that bid prices decreased with each successive auction. The weighted average price of projects executing RAM contracts decreased from approximately $90/MWh levelized post-TOD in RAM 1, to $88.75/MWh levelized post-TOD in RAM 2, to $79.82/MWh levelized post-TOD in RAM 3.[223] Parties do not contest these results.

The options for moving forward are reviewed below.

8.1.1. Authorize Additional Capacity and More Auctions

Some parties support continuing the RAM auctions in the existing or a similar form. Toward this end, parties suggest that the Commission authorize additional capacity into for RAM program, extend RAM through more auctions,

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220 December 31, 2013 ALJ Ruling at Attachment (Energy Division Summary & Questions on Future of RAM.) at 4. Each IOU held four auctions.

221 December 31, 2013 ALJ Ruling at Attachment (Energy Division Summary & Questions on Future of RAM.) at 5. The Energy Division has not compiled data on RAM 4 at the time the analysis was issued. RAM 5 had not been held at the time Energy Division issued its analysis.

222 December 31, 2013 ALJ Ruling at Attachment (Energy Division Summary & Questions on Future of RAM.) at 5.

223 December 31, 2013 ALJ Ruling at Attachment (Energy Division Summary & Questions on Future of RAM.) at 6.

and keep the structure similar to the existing RAM. The Joint Solar Parties,[224] National Resources Defense Council (NRDC),[225] and Clean Coalition[226] support this direction based on the rationale that RAM, in its current format, successfully promoted procurement of smaller renewable generation.

8.1.2. Optional Procurement Tool

SDG&E suggests the Commission reauthorize RAM as a component of the annual RPS Procurement Plan. More specifically, SDG&E recommends that the Commission authorize the utility to determine, at the utility's discretion, the need for a RAM solicitation and the specific protocols of that solicitation and suggests that the Commission authorize utilities to rely on a streamlined approval process by filing a Tier 1 Advice Letter requesting approval of the RAM solicitation protocols and standard contract.[227] Similarly, ORA suggests the Commission combine the RAM and RPS annual solicitation and, in addition, remove the MW targets for RAM procurement.[228] PG&E recommends treating RAM as a procurement option, used at the discretion of the utility, as part of the

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[224] The Joint Solar Parties consist of the Solar Energy Industries Association, the Large-Scale Solar Association, and the Vote Solar Initiative. The Joint Solar Parties recommend that the Commission authorize an additional 1,000 MW (shared between the IOUs). Joint Solar Parties January 30, 2014 comments at 5.

[225] NRDC January 30, 2014 comments at 10. NRDC recommends reauthorizing RAM by auctioning an addition 250 MW (shared between the IOUs) into the program every six months.

[226] Clean Coalition January 30, 2014 comments at 9. Clean Coalition recommends the Commission authorize an additional 1,000 MW (shared between the IOUs) and direct the utilities to hold four more auctions over two years.

[227] SDG&E January 30, 2014 comments at 7.

[228] ORA January 30, 2014 comments at 1.

annual RPS solicitation and used for procurement of resources below a certain size or to meet other specific procurement needs.[229]

8.1.3. Extending RAM with an Additional Auction – RAM 6

TURN suggests the Commission authorize one additional auction, a RAM 6 auction, to provide a procurement opportunity for smaller generation that can rely on the federal Investment Tax Credit and, in addition, as a backup auction for capacity from the program that could be viewed as available after failed RAM projects.[230]

TURN further mentions RAM as a means to meet any increased RPS procurement requirements under AB 327.[231]

In response to the AB 327 issue raised by TURN, PG&E states that, until the Commission acts on its discretionary authority under AB 327 to increase the renewable targets beyond 33%, it is premature to mandate additional RAM procurement to meet any increased target.[232] In response to TURN's suggestion to hold a RAM 6, SCE states that RAM 5 and the annual RPS solicitation offer opportunities to rely on the federal Investment Tax Credit.[233]

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[229] PG&E January 30, 2014 comments at 6.

[230] TURN January 30, 2014 comments at 2.

[231] TURN is referring to § 399.15(b)(3).the provision of AB 327 which authorizes the Commission to require renewable procurement targets above 33% after 2020. TURN January 30, 2014 comments at 4.

[232] PG&E February 14, 2014 reply comments at 3.

[233] SCE February 14, 2014 reply comments at 6.

8.2. The Future of RAM - Optional Component of Annual RPS Solicitation & RAM 6

In today's decision, we adopt a revised RAM that functions as a procurement tool within the annual RPS procurement plan process. We also require IOUs to hold one additional RAM auction to close by June 30, 2015, a RAM 6 auction. We view RAM 6 as a transitional process, to provide smaller renewable generation a procurement forum between now and the 2015 annual RPS solicitation when IOUs will be permitted to rely on the revised RAM procurement tool.

8.2.1. RAM – A Streamlined Procurement Tool

We find that, based upon the high number of bids into the RAM auctions, the market today for smaller renewable procurement around 20 MW has matured. The strength of the market is further demonstrated by the decrease in bid price. By simply continuing RAM with adding more capacity and more auctions, we would fail to recognize the growth of the market since 2010 and that the original purpose of RAM, *i.e.*, promoting the smaller renewable market and supporting the IOUs' RPS compliance goals, is not as central today. Furthermore, in contrast to the situation when the Commission adopted RAM, the IOUs today are in a positive position for meeting their statutory RPS compliance target for compliance periods 2011-2013 and 2014-2016 and are expected to meet their compliance period 2017-2020 obligations with relatively minimal additional procurement. Therefore, the original objectives of RAM have been met, and we decline to renew RAM under the same structure adopted in D.10-12-048, as suggested by some parties.

In examining whether RAM offers benefits to the market under a different objective to reflect current market conditions, we find merit in the suggestions of

SDG&E and ORA. As suggested by SDG&E and ORA, we find that RAM may provide IOUs with a procurement tool to facilitate more streamlined procurement for RPS needs. Furthermore, we find that RAM could provide IOUs with a tool to procure other Commission authorized renewable procurement, such as, any capacity authorized under the so-called green tariffs pending before the Commission pursuant to SB 43 and other system or local needs.[234] We expect IOUs to explain in their annual RPS procurement plan filings how any proposed RAM could satisfy an authorized procurement need, including, for example, system Resource Adequacy needs, local Resource Adequacy needs, RPS needs, reliability needs, LCR needs, GTSR needs, and any need arising from Commission or legislative mandates.

Accordingly, in all future RPS Procurement Plans filed by PG&E, SCE, and SDG&E, starting with the 2015 annual RPS procurement plans filings, the utilities shall include, at the discretion of the utility, RAM as a streamlined procurement tool. The parameters of the newly adopted RAM procurement tool are discussed below.

8.3. RAM Procurement Tool – As an Optional Component of Annual RPS Solicitation

We review the parameters of RAM based on the goal of allowing utility flexibility to use RAM to optimize its portfolio based on its procurement needs while providing a streamlined procurement tool.

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[234] R.13-12-010, *Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans* (December 19, 2014).

We start by reviewing the existing program components and determine whether it is reasonable to retain these existing components, modify the components, or omit them from the revised RAM.

8.3.1. Standard Contract – Required

We retain the standard contract requirement but require IOUs to seek Commission authorization for a revised standard contract to reflect changes to RAM adopted today. In D.10-12-048, we required a standard contract for RAM so provide a simplified approach.[235] Parties generally supported the continuation of this aspect of RAM so that RAM can continue to be a more streamlined contracting and approval process. We agree.

We find that a standard contract provides parties and the IOUs with a streamline process and direct the IOUs to update their RAM standard contract to reflect the changes to program adopted today.

8.3.2. Project Size Restrictions - Optional

In today's decision, we eliminate the project size restrictions from the RAM. Instead, the IOUs are authorized to determine the optimal maximum project size for any procurement targeted through RAM.

The Energy Division Analysis explored whether the eligible project size for RAM should be adjusted from the current 3-20 MW requirement.[236] The Energy Division Analysis indicates that, as a result of market evolution, smaller projects

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[235] D.10-12-048 at 46.

[236] December 31, 2013 ALJ Ruling at Attachment A (Energy Division Summary & Questions on Future of RAM) at 18.

are now successfully winning contracts in RAM, which demonstrates that smaller projects have become more cost competitive.[237]

Several parties suggest increasing the current cap of 20 MW. PG&E suggests expanding the project size cap to 50 MW or even more.[238] SDG&E suggests expanding the size eligibility after additional review of the issue in workshops.[239] SCE suggests entirely removing the project size limitations and allowing utilities to determine project size based on specific needs.[240] NRDC, TURN, and Joint Solar Parties support retaining the existing size restrictions, most importantly the 20 MW size cap.

We find it reasonable to remove the project size limitation entirely and to authorize utilities to establish the project size requirement based on their specific procurement needs at the time of the solicitation.

8.3.3. Project Categories - Retained

In today's decision, we retain the product category requirement.

The Commission in D.10-12-048 required the IOU to identify the types of products (peaking, non-peaking, baseload) it intended to procure through RAM. The Energy Division Analysis asked whether these product category distinctions and requirements should be maintained or adjusted.

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[237] December 31, 2013 ALJ Ruling at Attachment A (Energy Division Summary & Questions on Future of RAM) at 8.

[238] PG&E January 30, 2014 comments at 12.

[239] SDG&E January 30, 2014 comments at 11.

[240] SCE January 30, 2014 comments at 16-17.

Parties filed comments on this topic. SCE and SDG&E recommend removing project categories.[241] CalWEA states that RAM should be aligned with resource planning and RPS procurement process by removing any limits on resource type (peaking, non-peaking, baseload) and instead applying the LCBF bid-evaluation process.[242] Ormat and NRDC state that the product categories should be retained.[243]

We find it reasonable to retain the product categories on the basis that categories ensure a potential market for most products.

8.3.4. Restriction on Subdivided Projects – Optional

In today's decision, we eliminate the prohibition against subdivided projects participating in RAM.

The Commission in D.12-10-048 stated that utilities should identify in their bid protocols the criteria for determining whether a project bidder subdivided a project to circumvent the program's 20 MW eligibility requirement.[244] The Energy Division Analysis explored the appropriate technical criteria for determining whether a project is a stand-alone project or a subset of a larger

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[241] SCE states current project categories narrow competition across the entire RAM auction by segmenting resources and, as a result, failing to encourage robust competition, and yielding a sub-optimal selection of projects from a customer value perspective. SCE January 30, 2014 comments at 20. SDG&E states that the RAM product procurement requirements imposed to date have resulted in procurement that otherwise would likely not have taken place. In support of its argument, SDG&E asserts that the baseload category of RAM procurement has generally been much more expensive than the peaking and non-peaking content categories. SDG&E January 30, 2014 comments at 12.

[242] CalWEA January 30, 2014 comments at 5.

[243] Ormat January 30, 2014 comments at 5; NRDC January 30, 2014 comments at 13.

[244] D.10-12-048, Appendix A at 2-3.

project and whether subdivided projects should be allowed to participate in RAM.

Except for Ormat and NRDC, parties did not comment on this topic. Ormat states that subdivided projects should be eligible to participate in RAM because, Ormat claims, they are allowed to do so in the annual RPS solicitation.[245] NRDC states that subdivided solar projects should be precluded, but other resources should be permitted to subdivide.[246]

We find that the IOUs should define the terms of any future RAM solicitation to either include or exclude sub-divided projects since this allows IOUs to determine how to meet resources needs.

8.3.5. IOU Service Territory Locational Restrictions – Expanded

In this decision, we eliminate the requirement that RAM projects be located in the service territory of one of the IOUs and permit IOUs to procure anywhere within the CAISO control area including dynamically scheduled resources.

RAM originally required projects to be located in the service territory of PG&E, SCE, or SDG&E based on the rationale that limiting eligibility to the utilities' service territories would help ensure that RAM projects efficiently utilize the existing distribution system.[247] The Energy Division Analysis reviewed alternatives, such as, expanding the area to the entire CAISO control area, to all of California, or to the transmission network within the WECC service

[245] Ormat January 30, 2014 comments at 7-8.

[246] NRDC January 30, 2014 comments at 15; NRDC February 14, 2014 reply comments at 4.

[247] D.10-12-048, Appendix A at 3.

territory. The Energy Division Analysis also reviewed limiting the area to only those projects interconnecting to the distribution system in the service territories of PG&E, SCE, or SDG&E.

PG&E supports expanding RAM to the entire CAISO control area because resources can be scheduled and operated under a consistent set of CAISO rules and the same contracts provisions logically apply to these resources.[248] SDG&E supports expanding RAM to all of California and Imperial Irrigation District's service territory.[249] 8ME, LLC (8ME) suggests expanding to all of California and to permit projects located in Imperial Irrigation District's service territory and interconnecting to the CAISO directly or delivering to the CAISO via pseudo-tie.[250] Clean Coalition recommends limiting eligibility to only those projects interconnecting to the distribution system in PG&E's, SCE's, or SDG&E's service territories.[251] Both SCE and PG&E assert that resources located physically outside the CAISO Balancing Authority may present added complexity because the resources may not operate under the CAISO scheduling rules.[252]

We find it reasonable to expand the geographic location for RAM projects to increase the available pool of resources. We expand the RAM eligible area to the CAISO balancing area including dynamically scheduled resources because all projects within this area operate under the same CAISO scheduling and settlement rules. We approve a different eligibility area for RAM than currently

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[248] PG&E January 30, 2014 comments at 9-10.

[249] SDG&E January 30, 2014 comments at 10.

[250] 8ME February 14, 2014 reply comments at 1 and 2.

[251] Clean Coalition January 30, 2014 comments at 14.

[252] SCE January 30, 2014 comments at 15; PG&E January 30, 2014 comments at 10.

exists for the annual RPS solicitation, the WECC service territory, to retain the standard PPA feature of RAM. Expanding RAM to the entire WECC introduces a number of additional contract provisions and, as a result, does not support the use of a standard contract. The use of a standard contract is a critical component of the streamlined process provided in RAM.

8.3.6. RAM Valuation – Aligned with RPS Program

In this decision, we direct the IOUs to rely on Commission-approved LCBF methodology for bid ranking, consistent with the annual RPS program.

Under D.10-12-048, the RAM bid evaluation and selection was limited to the levelized post-TOD price ($/MWh) with adjustments for transmission network upgrade costs and resource adequacy benefits. The Energy Division Analysis reviewed whether other valuation factors should be included in the project ranking value.[253]

Several parties, including SCE, ORA, and SDG&E, recommend that RAM evaluation be consistent with RPS valuation and should use the approved LCBF methodology.[254] PG&E recommends using Portfolio-Adjusted Value, consistent with its 2013 RPS Plan.[255] Clean Coalition recommends including avoided transmission access charges and avoided line losses in valuation.[256]

We find it reasonable to require IOUs to use the same valuation methodologies used in the annual RPS solicitation because, by transitioning

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[253] December 31, 2013 ALJ Ruling at Attachment A (Energy Division Summary & Questions on Future of RAM) at 20.

[254] SCE January 30, 2014 comments at 21 and 23; ORA January 30, 2014 comments at 4; SDG&E January 30, 2014 comments at 9 and 13.

[255] PG&E January 30, 2014 comments at 16.

[256] Clean Coalition January 30, 2014 comments at 19-28.

RAM into a procurement tool that is part of the annual RPS solicitation process, aligning the RAM evaluation process with the current RPS program enables a broader comparison and the ability to select among various resources that are best suited to match the identified need. With a consistent valuation methodology for both the RAM procurement tool and RPS annual solicitation, IOUs can fairly compare resources across both procurement processes and select a resource that has the best value irrespective of where it was bid. We encourage parties to explore and improve on the valuation methodology in the RPS proceeding when it reviews LCBF.

8.3.7. Interconnection Studies – Phase II Study Required – Aligned with RPS Program

In this decision, we adopt the requirement that a Phase II Interconnection Study be obtained prior to participating in a utility's RAM procurement process consistent with the annual RPS solicitation requirement.

PG&E and SDG&E support adopting a Phase II interconnection study requirement for RAM. According to SDG&E, requiring a Phase II study will ensure higher project viability and ability to meet the guaranteed commercial operation date within 24 months.[257] PG&E supports adopting the Phase II interconnection study or equivalent requirement consistent with the eligibility rules adopted in the 2013 RPS Procurement Plan.[258] Joint Solar Parties support a Phase II interconnection study requirement because current interconnection requirements (System Impact Study, Cluster Study Phase I, or Fast Track screens) at the time of bid submittal have not been sufficient to ensure that commercial

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[257] SDG&E January 30, 2014 comments at 15.

[258] PG&E January 30, 2014 comments at 18.

operation commitments align with interconnection requirements.[259] NRDC opposes it because while these studies might provide greater certainty regarding deliverability of projects, they also present major costs to developers, many of whom are not ultimately selected.[260]

We find it reasonable to require a Phase II Interconnection Study (or equivalent) be required prior to participating in the RAM procurement process in an effort to increase project viability and further align with the annual RPS solicitation requirements.

8.3.8. Commercial Online Date – Modified

In this decision, we modify the requirement that RAM projects be on-line within 24 months with a six month extension for regulatory delay.

RAM as adopted in D.10-12-048, and as modified by Resolution E-4489, requires projects be online in 24 months with a six months extension due to regulatory delay. The Energy Division Analysis reviewed the continued benefits of this program component. PG&E supports this component and suggests up to 48 months with an available 12-month extension for regulatory delays.[261] Kruger suggests the Commission adopt a 36-month requirement to reach commercial operations with an extension for regulatory delay.[262]

Accordingly, we find it reasonable to adopt Kruger's recommendation of a 36 month with a six month extension for regulatory delays requirement. The adoption of this modified requirement is reasonable because it allows for more

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[259] Joint Solar Parties January 30, 2014 comments at 13.

[260] NRDC February 14, 2014 reply comments at 12.

[261] PG&E January 30, 2014 comments at 20.

[262] Kruger January 30, 2014 comments at 3 and 4.

flexibility and because the utilities no longer have near term RPS needs, but it still addresses the original concern of RAM, project viability. As such, this commercial online date requirement of on or before 36 months and 6 months extension for regulatory delays applies only to new projects. Existing projects

We see value in using RAM procurement as a tool to enable expedited and fast track approval for existing projects which require re-contracting. Therefore, we exempt existing RAM projects from going through viability screens again. These viability screens are described in D.10-12-048.[263] These screens include: (1) site control; (2) development experience; (3) commercial technology and; and (4) interconnection application.[264]

8.3.9. Commission Approval Process – Flexible

In this decision, we permit the IOUs to seek approval of RAM contracts through the Tier 2 Advice Letter process or IOUs may request approval of another approval process in their annual RPS procurement plan filings.

Several parties suggest retaining the current streamlined features of RAM that require the use a non-negotiable standard offer contract and the more expedited Tier 2 advice letter process.[265]

We find it reasonable to provide IOUs with the option to suggest an appropriate means of seeking approval in their annual RPS procurement plan filing. This would mean that when the IOUs propose relying on a RAM procurement process for a part of their RPS or other needs in their RPS

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[263] D.10-12-048, Appendix A, at 5.

[264] SCE November 10, 2014 comments at 13.

[265] SCE January 30, 2014 comments at 10-11; SDG&E January 30, 2014 comments at 8; LSA February 14, 2014 reply comments at 4.

procurement plan. We expect the IOUs to elaborate, in their procurement plan, how the proposed RAM procurement could satisfy a Commission authorized need, for example, a system Resource Adequacy need, a local Resource Adequacy need, RPS need, GTSR need, any need arising from Commission or legislative mandates, or a reliability need. The IOUs would also propose, for the Commission's approval, a process for the IOUs to seek approval of the contracts resulting from RAM. For example, if the IOUs proposed a RAM process based on a standard contract and sought on-line dates within 24 months, the IOUs could request approval through an expedited process, such as a Tier 2 Advice Letter. The Commission would review this proposal and approve or reject when the Commission issues its decision on the annual RPS Procurement Plans filings or other IOU authorization request. Our proposal today seeks to provide IOUs with the flexibility to adjust to the market by proposing transparent and reasonable means of obtaining approval of contracts under the revised RAM.

8.4. RAM 6 – Transitional Auction

Regarding the suggestions by parties to hold one additional RAM auction, a RAM 6, we find that a RAM 6 is reasonable to provide a forum for procurement of smaller resources in the short-term, until the revised RAM procurement tool may be offered in the 2015 RPS solicitation. We intend to use the lessons learned from RAM 6 to shape a more effective approach to supporting smaller resources and make future determinations regarding policy adjustments to support these smaller resources.

For these reasons, RAM 6 will continue to be a targeted auction to procure smaller renewable projects. The categories for peaking, non-peaking, and baseload should be maintained at proportions similar to those in the previous RAM solicitations, with the exact numbers to be chosen by the utilities.

The parameters of RAM 6 are summarized as follows:

(1) The MW capacity added to the program is noted in the below table. The noted MW does not include any remaining RAM capacity not included in contracts executed under Auctions 1 through 5 and capacity from any RAM 1 through 5 contracts terminated. This capacity shall be carried over from RAM 1-5 and added to RAM 6.

IOU	Allocation of Additional Capacity for RAM 6 (MW)
PG&E	32
SCE	33
SDG&E	10
Total	75

(2) Project size includes between >3 MW and20 MW.

(3) Peaking, non-peaking, and baseload categories should be maintained at similar proportions to previous RAM solicitations.

(4) The auction should close before June 30, 2015.

(5) The remaining program components are consistent with D.10-12-048.[266]

The capacity allocated today to PG&E for RAM 6 also must be increased to reflect our decision to close PG&E PV program in a separate proceeding, A.09-02-019, and move the some PV program capacity to RAM 6. Details of our decision are discussed below.

[266] LSA November 10, 2014 comments. LSA states it is unclear whether the Phase 2 study (or equivalent) requirement applies to RAM 6. It does not. LSA also states it is unclear how the restriction on subdivided projects applies to RAM 6. For subdivided projects, the rules that apply to RAM 5 also apply to RAM 6. PG&E November 10, 2014 comments at 7 similarly state the need for clarification of whether RAM 6 include the adopted items discussed in relationship to the revised RAM (the procurement tool). RAM 6 does not incorporate those items.

Accordingly, PG&E, SCE, and SDG&E shall hold a RAM 6 auction to close before June 30, 2015. PG&E, SCE, and SDG&E may file a Tier 2 Advice Letter to propose program changes if the proposed changes are ministerial, non-material, or in compliance with a Commission decision. Otherwise, a Tier 3 Advice Letter is required pursuant to the process adopted in D.10-12-048.

9. Petition for Modification of RAM by PG&E

Today, we grant PG&E's February 26, 2014 petition for modification seeking Commission authority to modify D.10-12-048 in order to transfer the remaining capacity in a separate renewable procurement program, PG&E's Solar PV program, to RAM and two other solicitations.

By way of background, in a separate decision also considered today, the Commission may grant, in part, PG&E's February 26, 2014 Petition for Modification of D.10-04-052.[267] This petition was filed and is being considered by the Commission in a separate proceeding, A.09-02-019. In this petition to modify D.10-04-052, PG&E requests to close its Solar Photovoltaic Program (Solar PV Program) established in D.10-04-052. If that request is granted, we will close the Solar PV Program for future solicitations, except for purposes of the administration of all existing contracts and facilities and compliance reporting.

In conjunction with PG&E's request to close its Solar PV Program, PG&E also requests in this proceeding that the Commission permit PG&E to procure the remaining capacity authorized in D.10-04-052 in the Solar PV Program to be

[267] The complete title of PG&E's February 26, 2014 filing is *Petition for Expedited Order Granting Modification of D.10-04-052 (Photovoltaic Program) and Approval of a Proposed Schedule for the Third Photovoltaic Program Power Purchase Agreement Solicitation.*

transferred to RAM. There are approximately 200 remaining MW in the Solar PV Program. We address the request to add this capacity to RAM here.

Provided that the Commission in A.09-02-019 grants PG&E's request to close its Solar PV Program, we find that PG&E's request to transfer any remaining capacity in the Solar PV Program to RAM is reasonable as it provides a means of offering this remaining capacity to the market while also increasing efficiency by consolidating the Commission's smaller procurement offering.

Therefore, PG&E's petition for modification is granted. One half of the remaining capacity in the Solar PV program is transferred to RAM 6. The remaining 1/2 is transferred and shall be offered in two future solicitations, one in 2016 and one in 2017. PG&E shall file an Advice Letter 1 to identify the number of MW transferred to RAM 6 and the amount transferred to those future solicitations to be held in 2016 and 2017. We expect the total capacity to be approximately 200 MW. This Advice Letter may be combined with any Tier 1 Advice Letter required by the Commission in A.09-02-019 to close the Solar PV Program.

10. PacifiCorp

PacifiCorp filed its 2013 Integrated Resource Plan on April 30, 2013. In this filing, PacifiCorp states its plan for providing reliable, reasonably cost service with manageable risks to its customers. PacifiCorp identifies the following as the key elements of its 2013 Integrated Resource Plan: (1) a finding of resource need for 2013-2022; (2) the preferred portfolio of incremental supply-side and demand-side resources to meet this need; and (3) an action plan identifying the steps that PacifiCorp will take during the next two to four years to implement the plan.[268]

With respect to meeting its RPS Program requirements, PacifiCorp states that it will issue, at least annually, requests for proposals seeking then current-year or forward-year vintage unbundled RECs. On March 31, 2014, PacifiCorp filed a 2013 IRP Update, and on July 15, 2014 filed its 2014 Off-Year Supplement to its 2013 IRP pursuant to the March 26, 2014 ACR.

In its 2014 Off-Year Supplement, PacifiCorp states that it will continue to issue requests for proposals for unbundled RECs at least annually to procure RECs to meet its California RPS requirements.[269] Additionally, PacifiCorp states that its market analysis leads it to believe that it will likely be able to purchase sufficient unbundled RECs to cover its California RPS compliance obligations through at least 2022.[270]

We find the Integrated Resource Plan and Off-Year Supplement consistent with Commission requirements.

11. Adopted Schedule for 2014 RPS Bid Solicitations

Today, we adopt a schedule that reflects its experience with the 2013 solicitation, as set forth in D.13-12-024, and prior solicitations. The adopted schedule provides utilities and the Energy Division Staff reasonable flexibility for contracts resulting from the solicitation. The utilities all propose schedules for

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[268] PacifiCorp's 2013 Integrated Resource Plan, Vol. I at 1.

[269] PacifiCorp's Off-Year Supplement to its 2013 Integrated Resource Plan, Attachment A at 3.

[270] PacifiCorp's Off-Year Supplement to its 2013 Integrated Resource Plan, Attachment A at 6

the 2014 RPS bid solicitations.[271] We sought information from parties regarding whether adjustments to the schedule would be used to conform more closely to the timeline for CAISO transmission studies. Parties indicated that no adjustments were needed. We will continue to seek input on the schedule in an effort to coordinate with other initiatives by the CAISO or other state agencies.

Consistent with prior years, the Commission authorizes the Energy Division Director, with notice to utilities and parties, to change the schedule as appropriate or as necessary for efficient administration of the 2014 RPS solicitation process. Parties may also seek schedule modification by letter to the Executive Director consistent with Rule 16.6 of the Commission's Rules of Practice and Procedure. To provide added flexibility to the schedule, this year we permit all solicitation dates included in the final RPS Procurement Plans to be adjusted by the utilities without prior Commission approval with the exception of the below noted dates.

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[271] PG&E's Draft 2014 RPS Procurement Plan, Appendix H at 7 and SCE's Amended Draft 2014 RPS Procurement Plan, Appendix F.1 at 13.

Schedule for 2014 Solicitation

Line No.	Item	No. of Days (cumulative)
1	Mailing of Commission decision conditionally accepting 2014 RPS Procurement Plans	0
2	PG&E, SCE and SDG&E file final 2014 RPS Procurement Plans	14
3	PG&E and SCE issue RFOs (unless amended Plans are suspended by the Energy Division Director by Day 24)*	24
4	PG&E and SCE submit shortlists to Commission and Procurement Review Group	120
5	PG&E and SCE file by Tier 2 advice letter (a) Evaluation Criteria and Selection Process Report and (b) Independent Evaluator's Report	150
6	PG&E and SCE 2014 RPS RFO Shortlists Expire	485
7	PG&E and SCE submit Advice Letters with contracts/power purchase agreements for Commission approval	TBD

*The utility may adjust this date to a day after Day 24, as necessary, without Commission approval.

12. Organization of 2015 RPS Procurement Plans and Supplements

For the next RPS procurement cycle, the Commission adopts the same procedural approach used for the 2006, 2007, 2008, 2009, 2011, 2012, 2013, and 2014 Plans.[272] The filing and service of 2014 draft RPS Procurement Plans and draft solicitation protocols by utilities is – consistent with prior years - expected to occur during the first half of 2014. The final schedule will be announced in a ruling. The ruling will also address the 2015 review of the ESPs' procurement

[272] D.05-07-039 at 29; D.06-05-039 at 58, D.07-02-011 at 61, D.08-02-008, *Opinion Conditionally Accepting Procurement Plans for 2008 RPS Solicitations* (February 2, 2008) at 46; D.09-06-018, *Decision Conditionally Accepting Procurement Plans for 2009 Renewables Portfolio Standard Solicitations and Integrated Resource Plan Supplements* at 70. No solicitations were held in 2011. *See* also, D.11-04-030, D.12-11-016, and D.13-12-024.

plans.[273] The multi-jurisdictional utility, PacifiCorp, may file Supplements or Integrated Resource Plans consistent with this decision, D.08-05-029, and D.11-04-030.

13. Motions for Confidential Treatment of 2014 RPS Draft and Amended Draft Procurement Plans – Granted, Except as Noted for Direct Energy Business

Unless otherwise addressed herein, all motions seeking confidential treatment of information set forth in the 2014 draft RPS Procurement Plans are granted.

We deny, in part, DEB's request for confidential treatment of its RNS information in its 2014 draft RPS Procurement Plans. We direct DEB to resubmit this information on a non-confidential basis in conformance with this decision.

The March 26, 2014 ACR directed PG&E, SCE, and SDG&E to provide quantitative information regarding their RPS portfolio needs and RPS procurement net short.[274] On May 21, 2014, the ALJ issued a Ruling on RNS and directed PG&E, SCE, and SDG&E, as well as Bear Valley Electric Service, Liberty Utilities LLC, PacifiCorp, and the to include a calculated RNS in their 2014 RPS Procurement Plans.

DEB filed its RNS in its 2014 RPS Procurement Plan. DEB also filed a motion seeking confidential treatment of portions of its RNS, pursuant to the Commission's confidentiality rules set forth in D.06-06-066 and D.08-04-023.[275]

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[273] D.11-01-026, Ordering Paragraph 1.

[274] March 26, 2014 ACR at 5.

[275] D.06-06-066, *Interim Opinion Implementing Senate Bill No. 1488, Relating to Confidentiality of Electric Procurement Data Submitted to the Commission* (July 5, 2006) and D.08-04-023, *Decision*

Footnote continued on next page

No parties filed comments in response to DEB's request for confidential treatment.

We deny, in part, DEB's motion for confidential treatment of its RNS on the basis that DEB redacted information beyond the allowable confidential treatment afforded by D.06-06-066 and D.08-04-023. Further, we find that public disclosure of much of the information that was redacted will not harm DEB. Additionally, we find that the public disclosure of the RNS is consistent with Commission decisions and the intent of Legislature to promote greater transparency regarding California's RPS program.[276]

Accordingly, DEB shall file a final 2014 RPS Procurement Plan with the Commission pursuant to the schedule adopted herein and shall make public information redacted in its draft 2014 RPS Procurement Plan, Appendix A, for years 2011 through 2013 and for years 2018 through 2033. Specifically, the information to be made public is as follows: Revised RNS Reporting Template_v2, RNS report tab, Columns F through J, Columns P through AF.

14. Comments on Proposed Decision

The proposed decision of ALJ DeAngelis in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on November 10, 2014 and reply comments

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*Adopting Model Protective Order and Non-Disclosure Agreement, Resolving Petition for Modification and Ratifying (*April 10, 2008).

[276] D.06-06-066, *Interim Opinion Implementing Senate Bill No. 1488, Relating to Confidentiality of Electric Procurement Data Submitted to the Commission* (July 5, 2006) at 60.

were filed on November 17, 2014. To the extent required, the proposed decision has been revised to reflect these comments.

15. Assignment of Proceeding

Carla J. Peterman is the assigned Commissioner and Regina M. DeAngelis is the assigned ALJ in this proceeding.

Findings of Fact

1. All retail sellers filing 2014 RPS Procurement Plans incorporated a section on safety considerations regarding the procurement of electricity in their RPS annual procurement plan filing.

2. The IOUs' 2014 RPS Plans do not address or seek authorization for renewable procurement in excess of the current RPS Program's 33% requirement.

3. The CAISO's modification to the LCBF methodology to use the CAISO's 10-year forecast of expected import capability for calculating the capacity benefit portion of an offer's LCBF evaluation, instead of the assumed 1,400 MW of import capability, eliminates previous concerns of the Commission that the CAISO was attributing zero import capability from the IID.

4. While the Commission is encouraged by the execution of contracts in the Imperial Valley area and successful development of new renewable energy facilities, only a small portion of the executed contracts are operational.

5. To support a streamlined procurement process, IOUs may modify their annual RPS Procurement Plans via a Tier 1 Advice Letter after the Commission approves the final plans to correct typographical errors, clarify requirements, incorporate directions provided by the Commission, or other non-material changes.

6. The Commission does not seek to discourage the participation of smaller projects in the RPS annual solicitation.

7. The Commission is currently considering a green tariff program in the pending consolidated proceeding of A.12-01-008, A.12-04-020, and A.14-01-007.

8. When SCE relies on one set of TOD factors that apply to all projects, projects are treated consistently with respect to obtainment of FCDS.

9. PG&E's TOD factors account for its unique resource and market needs.

10. More certainty is needed regarding whether SDG&E's proposal to rely on the flat TOD factor of 1.0 for purposes of contract pricing will discourage generators to minimize the cost of their bid by providing a generation profile that places more generation in the off-peak hours.

11. Each IOU has its own unique resource and market needs which must be taken into account when developing their TOD factors.

12. Uniformity in the methods used by the IOUs to calculate and apply TOD factors is not essential.

13. Uniform TOD factors across an IOU's RPS programs promotes fairness.

14. SCE evaluates a potential project on the basis of certain design elements and the Commission approves of the resulting contract expecting a certain value and cost to ratepayers. When material changes occur to certain aspects of a project after Commission approval, value to ratepayers may be negatively impacted. The same applies to PG&E and SDG&E.

15. The Investment Tax Credit is currently set to expire in the near future. The Production Tax Credit has expired. Congress may adopt measures to extend these two tax credits.

16. By keeping the documents related to the solicitation current, SDG&E will promote market transparency even though it will not hold a 2014 solicitation.

17. SDG&E's showing regarding its compliance with current statutory RPS procurement mandates justifies granting SDG&E's request to not holding a

solicitation in 2014. SDG&E is required to hold a RAM solicitation and perhaps other solicitations for smaller projects.

18. Shortlist exclusivity may reduce transaction costs but shortlist exclusivity continues to be an unnecessary restriction on the market based on the current level of competition.

19. The proposed changes to the excess capacity provisions in the pro forma contracts will limit customer exposure to incremental costs. If a seller would like to produce more energy, the seller is encouraged to offer a higher contract capacity during the bidding process.

20. Occurrences of negative locational marginal pricing are increasing.

21. The IOUs are working to minimize or avoid the need for curtailment.

22. Adopting the requirement that the project demonstrates it has reached the "application deemed completed "(or equivalent) status within the applicable land use entitlement process by the agency designated as the *lead agency* under CEQA as a prerequisite to bidding into the RPS solicitation is likely a demonstrable step toward site control and should provide increased assurance that project is progressing towards development at the time of bidding.

23. Not all projects require an Initial Study under the CEQA or under the National Environmental Policy Act.

24. Resources adequacy valuation is an important component in the LCBF methodology.

25. The March 26, 2014 ARC proposed that the LCBF methodology include a resource adequacy valuation of zero to reflect the finding in the LTPP proceeding of no need to procure additional system capacity.

26. Increases in intermittent renewable generation may require the grid system to be more operationally flexible to ensure adequate system reliability.

27. More detailed work is needed before a final renewable integration cost adder valuation methodology is adopted by the Commission.

28. The record development for a final methodology is an on-going process and, as of today, is not sufficiently developed to provide a basis for a decision on a final integration cost adder.

29. CalWEA's proposal for calculating an integration cost adder, by relying on zero value for two of its proposed components due to the unavailability of information, fails to move the issue forward sufficiently right now.

30. Moving forward on valuing the renewable integration cost adder is an important goal of the Commission.

31. Strengthening the data adequacy requirements applicable to advice letters and other processes used by IOUs to seek approval of procurement-related matters supports the Commission's review process.

32. Additional data related to the GIS files of PG&E, SCE, and SDG&E will promote a greater understanding by the Commission of RPS procurement needs.

33. No specified timeline for filing the advice letter seeking approval of the shortlist of bids currently exists, which leaves the process open to unreasonable delay.

34. The Tier 2 Advice Letter process provides the appropriate level of oversight to review the shortlist of bids. A Tier 3 Advice Letter process contradicts our goal of streamlining the RPS procurement review process.

35. Creating more structure and predictability around the Commission review process, as envisioned by the Energy Division's proposal to establish a date certain for seeking Commission approval of an RPS contract, may further encourage timely decision-making based on current market information. The

Energy Division proposes that utilities file for approval 90 days from the date of execution of RPS contracts.

36. The Energy Division's proposal for a 12-month timeline for contract negotiations may result in undue and unknown pressures on the contracting parties, which may even result in increased ratepayer costs. In addition, the proposal appears to overlap with our existing rule adopted in D.12-11-016 that the shortlist expires within 12 months.

37. Streamlining the review process for RPS contracts is a goal of the Commission.

38. A separate pro forma contract for short-term contracts, but not a separate standard contract, will benefit the parties and the ratepayers by providing additional structure for the negotiation process.

39. Uniform Standards of Review for a RPS transactions, as noted in the Energy Division proposal and with an exception for certain amendments, supports administrative efficiency and transparency.

40. To date, the Commission has not adopted any specific review and reporting guidelines for Independent Evaluators. In the past the Energy Division has provided Independent Evaluators with reporting templates with the information that must be included in the reports regarding the RPS solicitations and contracts.

41. RAM, as authorized by the Commission in D.10-12-048, has ended.

42. The market today for smaller renewable procurement around 20 MW has matured compared to when the Commission adopted D.10-12-048.

43. The original goals of RAM are not as central today because IOUs are now in a positive position for meeting their statutory RPS compliance target for compliance periods 2011-2013 and 2014-2016 and are expected to meet their

compliance period 2017-2020 obligations with relatively minimal additional procurement.

44. An additional RAM solicitation, such as RAM 6, may offer support for smaller renewables before the next annual RPS solicitation, which probably will be held in late 2015.

45. Transferring ½ the capacity remaining in PG&E's Solar PV program to RAM 6 and the remaining capacity to be offered equally in solicitation to be held in 2016 and 2017 will promote administrative efficiency and provide a means to offer this capacity to the market

Conclusions of Law

1. The 2014 draft RPS Procurement Plans, as updated or amended, are acceptable in terms of the information provided on safety considerations.

2. The Commission must first implement AB 327. Only then will the IOUs need to act in compliance with any new directive the Commission adopts consistent with AB 327.

3. Continued direct monitoring of renewable procurement activities in the Imperial Valley area is reasonable because it enables the Commission and the public to observe the progress of renewable facilities development in the area.

4. It is reasonable to approve of SCE's LCBF methodology that calculates resource adequacy benefits based on CAISO's Advisory Estimates of Future Resource Adequacy Import Capability because this methodology has been modified to eliminate prior areas of concern.

5. It is reasonable to remove the Commission's requirement to assume a maximum import capability of 1,400 MW from IID Balancing Authority Area as directed in June 7, 2011 ACR and D.12-11-016.

6. After an IOU obtains § 399.13 approval of an RPS Procurement Plan, any changes to the documents included therein, must be approved by the Commission. To correct typographical errors, clarify requirements, incorporate directives from the Commission, or other non-material revisions, it is reasonable for IOUs to rely on a Tier 1 Advice Letter. A pro forma contract may be changed during the negotiation process. Nothing in statutory law prevents the Commission from approving changes to the RPS procurement plans after the Commission "accepts, modifies, or rejects" the RPS Plans under § 399.13(a)(1).

7. Decreasing the minimum project size to 500 kW for all future solicitations is reasonable because the Commission wants to encourage the participation of smaller projects in the RPS annual solicitation.

8. It is not reasonable to modify the annual RPS solicitation to accommodate the SB 43 program because the Commission has not yet adopted an SB 43 program.

9. Because each IOU must meet its own unique resource and market needs, it is reasonable not to require uniformity in the methods used by the IOUs to calculate and apply TOD factors.

10. SCE's request to reply on one set of time-of-delivery factors is reasonable because different technologies are treated consistently with respect to obtainment of FCDS.

11. PG&E's proposal to rely on two sets of TOD factors, one set of TOD factors for energy-only and another set of TOD factors for FCDS, is reasonable because the two sets, as opposed to a single set, are designed to meet its unique resource and market needs.

12. It is reasonable to reject SDG&E's proposal to rely on the flat TOD factor of 1.0 for purposes of contract pricing because additional information is needed to assess this proposal.

13. It is reasonable to authorize IOUs to update their TOD factors to be uniform across all RPS programs because uniformity supports fairness.

14. SCE's proposed modification to Section 3.11(d), which includes, but is not limited to, project site location, photovoltaic module specification, and major electrical equipment specification of its 2014 RPS Procurement pro forma contract is a clarification and reasonable because SCE should have the right to review and accept or reject material changes to the matters set forth in Section 3.11(d) that impact the results of the competitive bidding process and may harm SCE's customers, as the proposed modifications may increase ratepayer costs or diminish the contracts' value. The same applies to PG&E and SDG&E.

15. SCE's proposal to remove the provisions related to the Investment Tax Credit and the Production Tax Credit is rejected because it is possible for Congress to extend these provisions, as it has done in the past.

16. Each utility remains responsible for meeting its RPS Program procurement requirements implemented in D.11-12-020.

17. SDG&E's request to update its solicitation materials is reasonable because, in this manner, SDG&E will keep the documents current even if no 2014 solicitation is held.

18. Based on SDG&E's current stated compliance with RPS procurement, it is reasonable to approve of SDG&E's request not to hold a 2014 solicitation.

19. Affirming our finding in D.13-11-024 that the contract negotiating arrangement referred to as *shortlist exclusivity* will not be permitted is reasonable

because it is an unnecessary restriction on the market based on the current level of competition.

20. It is reasonable for the IOUs to modify their pro forma contracts consistent with SCE's suggested modification to the excess delivery provisions because the seller and utility agree on a contract quantity and expect the seller to construct a facility consistent with the terms of the contract.

21. It is reasonable to approve of the terms and conditions regarding curtailment set forth in the IOUs' 2014 RPS Procurement Plan because the provisions provide some ratepayer protection against the risk of negative locational marginal pricing and also allow the contracts to be financeable.

22. It is reasonable to require multiple variants of an offer for the purpose of gaining market information related to the need for economic curtailment.

23. SCE's proposal to require two bid offer variants related to economic curtailment is reasonable because the multiple options could help determine the value of a curtailment cap.

24. It is reasonable to require PG&E to clarify how it will value economic curtailment because is unclear how the adder will be calculated and how the amount of curtailed hours offered will affect the adder calculation.

25. It is reasonable to require the utilities to include in their 2014 RPS solicitation shortlist reports the curtailment variants received and how the amount of curtailment offered impacted the utilities' shortlisting of bids because additional data is needed to evaluate this issue.

26. It is reasonable to require projects to demonstrate, at a minimum, an "application deemed complete" (or equivalent) status within the applicable land use entitlement process by the agency designated by the California Environmental Quality Act or National Environmental Policy Act as the *lead*

agency as a prerequisite to participating in the 2014 RPS solicitations because this added requirement may increase overall project viability.

27. The requirement that all projects demonstrate an Initial Study under the CEQA or under the National Environmental Policy Act as a prerequisite to participation in the 2014 solicitation may unnecessarily limit participation because not all projects require an Initial Study and, as a result, the requirement does not apply to such projects.

28. It is reasonable that the "application deemed complete" (or equivalent) requirement may be fulfilled by the developer providing a copy of the letter from the land use permitting agency documenting that the land use permit application for the project has been "deemed complete" to begin the permitting review process or by other reasonable means.

29. It is reasonable to decline to adopt the March 26, 2014 ACR proposal that resource adequacy be valued at zero in the utilities' LCBF methodologies for their annual 2014 RPS solicitations because resource adequacy is a defined product with market value and the lack of need for resource adequacy will be reflected in low resource adequacy values, not necessarily a zero value.

30. We find that an interim approach for calculating an integration cost adder is reasonable, especially in light of the strong interest expressed by both the parties and by the legislature through AB 2362 in making progress on this issue.[277]

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[277] The legislature approved AB 2363 (Dahle, Stats. 2014, ch. 610), to impose a timeline on the Commission for consideration and adopting of an integration cost adder. This bill was chaptered on September 26, 2014.

31. CalWEA's interim proposal for an integration cost adder is not adopted due to the unavailability of the needed information to complete its proposal.

32. PG&E's interim proposal for an integration cost adder is reasonable because, although additional refinement is needed, the proposal calculates a value based on existing data, presents a conservative approach that is appropriate for use on an interim basis, and will assist with the next step of more accurately reflecting costs resulting from renewable resources.

33. It is reasonable to accept the Energy Division's proposal on general data adequacy applied to procurement review as this aspect of the proposal serves to strengthen the data requirements already in place.

34. With regard to the Energy Division's proposal that environmental data adequacy requirements apply to procurement review, it is reasonable to not adopt the suggestions by the Energy Division, with one exception, based on concerns that the recommended additional data requirements are duplicative of the existing environmental permitting process in California and the need to better understand the impact on the entire permitting process that may result from requiring the additional environmental requirements suggested by the Energy Division.

35. It is reasonable to request PG&E, SCE, and SDG&E to provide the GIS file regarding certain data to promote the Commission's understanding of procurement needs.

36. The Energy Division's proposal that the advice letter seeking approval of the utilities' shortlists of bids be filed with a certain number of days after the close of the solicitation is reasonable because a definitive timeline will function to create more structure and predictability around the process, and, in this manner, prevent unreasonable delay.

37. The Tier 2 Advice Letter process will remain the process for utilities to seek approval of shortlists because it provides the appropriate level of oversight of this issue.

38. The Energy Division's proposal to establish a date certain, 90 days after contract execution, before which the utilities must file advice letters or other appropriate filing seeking Commission approval of executed RPS contracts is reasonable because the proposal functions to create more structure and predictability around the Commission review process, and, in this manner, encourage timely decision-making based on current market information.

39. The Energy Division's proposal for a 12-month timeline for contract negotiations is not reasonable because it may result in undue and unknown pressures on the contracting parties, which may even increase ratepayer costs. In addition, it appears to overlap with our existing rule adopted in D.12-11-016 that the shortlist expires within 12 months.

40. It is reasonable to modify the current process for utilities to seek approval of a short-term contract (under five years) by authorizing the use of a Tier 1 Advice Letter, rather than a Tier 3 Advice Letter, because this modification will streamline the review process but maintain the appropriate level of Commission oversight for these short-term contracts.

41. It is reasonable to clarify that the so-called *fast track* process adopted in D.09-06-050 is superseded and replaced by today's decision to adopt a streamlined process for review of short-term contracts (under 5 years) via a Tier 1 Advice Letter.

42. Providing a pro forma contract specifically designed for negotiation for short-term transaction is reasonable because this modification will provide additional structure for the negotiation process.

43. It is reasonable to adopt the Energy Division proposal to establish Standards for Review for RPS transaction because it will further the Commission's goal of supporting efficiency and transparency in the contract review process. By requiring uniformity across the Standards of Review, the Commission furthers these goals.

44. The Energy Division's proposal for the Commission to adopt specific reporting guidelines for Independent Evaluators rather than rely on currently used informal requests by the Energy Division should not adopted because retaining the flexibility of the current process is preferred. The Energy Division has the authority to request any needed information from the Independent Evaluator.

45. It is reasonable to adopt a revised RAM that functions as a procurement tool within the annual RPS procurement plan process because the revised RAM may provide IOUs with a procurement tool to facilitate more streamlined procurement for RPS needs and, in addition, with a tool to procure other Commission authorized renewable procurement, such as, any capacity authorized under the so-called green tariffs pending before the Commission pursuant to SB 43 and other system or local needs.

46. It is reasonable to require the IOUs to hold one additional RAM auction to close by June 30, 2015, a RAM 6 auction, because RAM 6 will function as a transitional process, to provide smaller renewable generation a procurement forum between now and the 2015 annual RPS solicitation when IOUs will be permitted to rely on the revised RAM procurement tool.

47. PG&E's request in its February 26, 2014 Petition for Modification to transfer capacity to RAM is reasonable based the Commission's continued interested in a RAM solicitation. The request is granted, with certain restrictions.

48. All motions for confidential treatment should be granted unless otherwise noted.

49. All motions for party status should be granted.

50. DEB's request for confidential treatment of its Renewable Net Short information in its 2014 draft RPS Procurement Plans should be denied because it fails to conform to existing law governing confidential data.

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 2014 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 conditionally accepted, as modified in the Ordering Paragraphs that follow.

2. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall file final Renewables Portfolio Standard (RPS) Procurement Plans with the Commission to initiate the RPS solicitation process within 14 days of the mailing date of this decision pursuant to the RPS solicitation schedule adopted in Ordering Paragraph 33.

3. The 2014 Renewables Portfolio Standard Procurement Plans filed by the smaller utilities, Bear Valley Electric Service and Liberty Utilities LLC are accepted and deemed final. No further filings are required.

4. Pursuant to Public Utilities Code Section 365.1(c)(1), the 2014 Renewables Portfolio Standard Procurement Plans filed by electric service providers are

accepted and deemed final, including: 3 Phases Renewables, LLC, Calpine PowerAmerica-CA, LLC's, Commerce Energy, Inc., Commercial Energy of California, Constellation NewEnergy, Inc., Direct Energy Services, LLC, EDF Industrial Power Services, LLC, Gexa Energy California, LLC, Glacial Energy of California, Inc., Liberty Power Holdings, LLC, Noble Americas Energy Solutions LLC, Palmco Power CA, LLC, Pilot Power Group, Inc., Shell Energy North America (US), L.P., Southern California Telephone & Energy, Tenaska California Energy Marketing, LLC, Tenaska Power Services Company, The Regents of the University of California, Tiger Natural Gas, Inc., and Yep Energy. No further filings are required, except for Direct Energy Business, LLC. Direct Energy Business, LLC shall resubmit its 2014 Plan on a non-confidential basis, as required by law.

5. PacifiCorp's July 15, 2014 Off-Year Supplement to its 2013 Integrated Resource Plan is deemed final. No further filings are required.

6. All future Renewables Portfolio Standard annual procurement plans filed pursuant to Public Utilities Code Section 399.11 *et seq*. must include a separate section addressing safety considerations.

7. The Commission's Energy Division Staff shall continue to monitor development of projects under the Renewables Portfolio Standard Program in the Imperial Valley according to the parameters set forth in Appendix A of Decision 09-06-018.

8. Consistent with Decision 12-11-016, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall provide a specific assessment of the offers and contracted projects in the Imperial Valley region in future Renewables Portfolio Standard Procurement

Plans filed with the Commission pursuant to Public Utilities Code Section 399.11 *et seq*. until directed otherwise.

9. Southern California Edison Company is authorized to include its least-cost, best-fit methodology that calculates resource adequacy benefits based on California Independent System Operator's Advisory Estimates of Future Resource Adequacy Import Capability in its final Renewables Portfolio Standard Procurement Plan filed with the Commission pursuant to the schedule adopted herein.

10. In their final RPS Procurement Plan, Pacific Gas and Electric Company and San Diego Gas & Electric Company shall, as applicable, remove the assumption of a maximum import capability of 1,400 MW from Imperial Irrigation District Balancing Authority Area adopted in the June 7, 2011 Assigned Commissioner's Ruling and Decision 12-11-016 and may base resource adequacy calculations on California Independent System Operator's *Advisory Estimates of Future Resource Adequacy Import Capability*.

11. In the final Renewables Portfolio Standard (RPS) Procurement Plans filed pursuant to the schedule adopted herein, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall obtain Commission approval to change the material included in their Plan after the Commission approves the RPS Procurement Plans under Section 399.13(a)(1). After the Plans are approved by the Commission, the utilities may seek Commission approval to correct typographical errors, clarify requirements, incorporate directives from the Commission, or other non-material revisions via a Tier 1 Advice Letter.

12. In the final 2014 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein,

Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall reduce the minimum threshold for project size eligibility to 500 kW. The modification shall apply in all future RPS Procurement Plans until the Commission directs otherwise.

13. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are directed to seek authorization to conform the Renewables Portfolio Standard Program to any Senate Bill 43 green tariff program after the Commission adopts such a program.

14. In the final 2014 Renewables Portfolio Standard (RPS) Procurement Plans filed with the Commission pursuant to the schedule adopted herein: (1) Pacific Gas and Electric Company (PG&E) is authorized to rely on two sets of Time-of-Delivery (TOD) factors, energy-only and Full Capacity Deliverability Status, as set forth in its 2014 draft RPS Procurement Plan; (2) Southern California Edison Company (SCE) is authorized to rely on a single set of TOD factors as set forth in its 2014 draft Procurement Plan; and (3) San Diego Gas & Electric Company (SDG&E) shall update its TOD factors and remove the flat-rate component. In addition, PG&E, SCE, and SDG&E are authorized to file Tier 1 Advice Letters to request the Commission to approve of conforming TOD factors across all the RPS procurement programs. PG&E, SCE, and SDG&E may file Tier 1 Advice Letters to seek authority to conform their TOD factors on-going basis until the Commission directs otherwise.

15. In the final 2014 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Southern California Edison Company is authorized to include the proposed modification to Section 3.11(d) of its 2014 RPS Procurement pro forma agreement. Pacific Gas and Electric Company and San Diego Gas and Electric

Company are authorized to include similar provisions in their final 2014 RPS Procurement Plans.

16. In the final 2014 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall not remove the provisions related to the federal tax credits, the Investment Tax Credit and the Production Tax Credit.

17. San Diego Gas & Electric Company (SDG&E) is authorized to not hold a 2014 Renewables Portfolio Standard (RPS) solicitation and shall indicate in its Final 2014 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 2014 solicitation cycle. SDG&E shall file a final 2014 RPS Procurement Plan with updated solicitation material even though no solicitation is scheduled for 2014. This authorization to not hold a solicitation only applies for one year, 2014.

18. Consistent with Decision 13-12-024, in the final 2014 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are not authorized to require shortlist exclusivity as part of the contract negotiating process.

19. In the 2014 Renewables Portfolio Standard Procurement Plans filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are authorized to incorporate the excess delivery terms set forth in their draft plans.

20. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall continue to incorporate and describe how expected economic curtailment affects their Renewables Portfolio Standard (RPS) procurement in future RPS procurement plans. PG&E's, SCE's, and SDG&E's pro forma terms and conditions related to economic curtailment are approved as proposed. PG&E shall modify its RPS protocols such that each offer is to include at least two variants that offer different amounts of economic curtailment hours. PG&E shall modify its least-cost, best-fit description of its Curtailment Hours adder such that it is clear how bids will be evaluated if they offer less than full economic curtailment rights. PG&E and SCE shall include in their 2014 RPS solicitation shortlist reports information regarding how the offers' economic variants differed and how economic curtailment was considered in their shortlisting processes.

21. In the final 2014 Renewables Portfolio Standard (RPS) Procurement Plans filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall modify their 2014 RPS solicitation protocols to require that projects have achieved, at a minimum, an "application deemed complete" (or equivalent) status within the applicable land use entitlement process by the agency designated by the California Environmental Quality Act or National Environmental Policy Act as the *lead agency* as a prerequisite to participating in the 2014 RPS solicitations. The requirement shall apply to all future annual RPS Procurement solicitations until the Commission directs otherwise.

22. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall provide to their respective Procurement Review Groups (PRGs) and the Energy Division their resource adequacy price curve forecasts in their shortlist reports along with a description of the methodology used to develop the curve to ensure that they are consistent with current market resource adequacy values as well as Long-Term Procurement Plan (LTPP) system need forecasts. The utilities' shortlist reports shall also explain how their resource adequacy price forecast is consistent with the market and LTPP forecasts. PG&E, SCE, and SDG&E shall also provide to their respective PRGs their two bid rankings using resource adequacy valuations calculated with Net Qualifying Capacities based on (1) the exceedance methodology and (2) an Effective Load Carrying Capacity methodology.

23. In the final 2014 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) shall incorporate an interim integration cost adder for the 2014 RPS solicitation consistent. These interim values shall be integrated within the least-cost, best-fit methodology for 2014. PG&E and SCE shall update their LCBF methodologies to include a description of how they will calculate integration cost adders based on the adopted interim methodology. The description should clearly describe the methodology for calculating the adder, the components of the adder, the source for any variables used to calculate the adder and its components, and how the adder will be applied to a bid in its evaluation. A final methodology will be considered in this proceeding and in coordination with Rulemaking 13-12-010 or other proceeding. Until a final methodology is adopted, the Commission authorizes minor changes to be made to this methodology by ruling. This

interim integration cost adder valuation will remain in place until a final valuation is adopted by the Commission.

24. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall comply with the adopted general data adequacy and Geographical Information Systems (GIS) data requirement herein. These requirements are as follows: (1) the shortlist advice letter template must be complete, (2) the contract/power purchase agreement advice letter template must be complete, (3) all required Excel/Word workpapers must be complete, and (4) a GIS file of the project boundaries and associated gen-tie for all projects that currently have an RPS PPA and for all future RPS bids submitted to annual RPS solicitations or RPS procurement programs. The Director of Energy Division shall request the GIS data as needed and the utilities shall provide the requested GIS date to the Director of the Energy Division.

25. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall revise their Renewables Portfolio Standard (RPS) protocols, as needed, to account for filing the already required advice letter with their bid shortlists 100 days after the close of their RPS solicitations. All requests for extension must be made to the Commission's Executive Director pursuant to Rule 16.6 of the Rules of Practice and Procedure.

26. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) shall revise their Renewables Portfolio Standard (RPS) solicitation protocols, as needed, to reflect the requirement that, within 90 days from the date of execution of a RPS contract, PG&E, SCE, and SDG&E shall file with the Commission seeking approval of that contract. This requirement applies to all future RPS solicitations unless otherwise stated by the Commission.

27. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) are authorized to seek Commission approval of short-term Renewables Portfolio Standard (RPS) sales and purchase contracts (5 years of less) through a Tier 1 Advice Letter. Each sale and purchase contract shall be filed in a separate advice letter. PG&E, SCE, and SDG&E shall not rely on the *fast track* process approved in D.09-06-050. The Energy Division is authorized to modify the RPS Advice Letter Template as necessary to accommodate this change. PG&E, SCE, and SDG&E shall provide a separate pro forma contract for short-term transactions with their annual RPS Plans in 2015.

28. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall seek to comply with the uniform Standards of Review when seeking approval of transactions within the Renewables Portfolio Standard (RPS) Program. The Energy Division is authorized to request the utilities to provide information in a specific format.

29. The Energy Division shall continue its role of refining the elements of the Independent Evaluator Reports on an on-going basis to ensure that the Independent Evaluator Reports provide useful information that reflect the changing markets. The Energy Division, at its discretion, may direct Independent Evaluators to include the following in their reports:
(1) reasonableness and accuracy of least-cost best-fit methodology;
(2) reasonableness of price and value of projects shortlisted; (3) viability of projects on shortlist; (4) approved renewable net short; and (5) any relevant safety considerations.

30. In all future Renewables Portfolio Standard (RPS) Procurement Plans filed by Pacific Gas and Electric Company, Southern California Edison Company, and

San Diego Gas & Electric Company, starting with the 2015 annual RPS procurement plans filings, the utilities shall include, at the discretion of the utility, the Renewable Auction Mechanism (RAM) as a streamlined procurement tool. The parameters of the newly adopted RAM procurement tool include: (1) a standard contract; (2) product categories; (3) expanded service territory; (4) align RAM valuation methodology with RPS Program; (5) require a Phase II Interconnection Study; (6) a commercial online date of on or before 36 month with a 6 month extension for regulatory delays requirement for new projects; and (7) a flexible approval process.

31. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall hold a Renewable Auction Mechanism 6 auction to close before June 30, 2015.

32. The Petition for Modification filed by Pacific Gas and Electric Company (PG&E) on February 26, 2014 seeking authority to transfer capacity from its Solar Photovoltaics (Solar PV) Program to the Renewable Auction Mechanism (RAM) is granted, with certain restrictions. PG&E shall file a Tier 1 Advice Letter to advise the Commission of the amount of capacity remaining in the Solar PV Program. PG&E shall transfer ½ of the remaining capacity, including failed or terminated capacity, to RAM 6. The remaining ½ shall be transferred equally to two solicitations held in 2016 and 2017.

33. The following schedule is adopted for the 2014 Renewable Portfolio Standard (RPS) solicitation:

Schedule for 2014 RPS Solicitation

Line No.	Item	No. of Days (cumulative)
1	Mailing of Commission decision conditionally accepting 2014 RPS Procurement Plans	0
2	PG&E, SCE and SDG&E file final 2014 RPS Procurement Plans	14
3	PG&E and SCE issue RFOs (unless amended Plans are suspended by the Energy Division Director by Day 24)*	24
4	PG&E and SCE submit shortlists to Commission and Procurement Review Group	120
5	PG&E and SCE file by Tier 2 advice letter (a) Evaluation Criteria and Selection Process Report and (b) Independent Evaluator's Report	150
6	PG&E and SCE 2014 RPS RFO Shortlists Expire	485
7	PG&E and SCE submit Advice Letters with contracts/power purchase agreements for Commission approval	TBD

*The utility may adjust this date to a day after Day 24, as necessary, without Commission approval.

The Energy Division Director is authorized, after notice to the service list of this proceeding, to change the schedule as appropriate or as necessary for the efficient administration of the 2014 Renewables Portfolio Standard solicitation process.

34. All motions for confidentiality are granted except as noted.

35. All motions for party status are granted.

36. Rulemaking 11-05-005 remains open.

This order is effective today.

Dated November 20, 2014, at San Francisco, California.

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
MICHAEL PICKER
Commissioners