Decision **PROPOSED DECISION OF ALJ DEANGELIS** (Mailed 10/9/2012)

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 2012 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS AND INTEGRATED RESOURCE PLAN OFF-YEAR SUPPLEMENT

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DECISION CONDITIONALLY ACCEPTING 2012 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS AND INTEGRATED RESOURCE PLAN OFF-YEAR SUPPLEMENT

1. Summary

Pursuant to the authority provided in Pub. Util. Code § 399.13(a)(1),[1] today's decision conditionally accepts, as modified herein, the 2012 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 SCE's request in its August 15, 2012 updated RPS Procurement Plan not to hold a 2012 RPS solicitation but reject SCE's request to execute bilateral contracts during the time period covered by its 2012 RPS Procurement Plan.

We direct PG&E and SDG&E to file final RPS Procurement Plans with the Commission to initiate the RPS solicitation process within 15 days of the mailing date of this decision pursuant to the RPS solicitation schedule adopted herein. While SCE will not hold a 2012 solicitation, we direct SCE to file a final RPS Procurement Plan within 15 days of the mailing date of this decision to reflect modifications adopted herein.

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[1] § 399.13(a)(1) orders the Commission to "direct each electric corporation to annually prepare a renewable energy procurement plan…to satisfy its obligations under the renewables portfolio standard." All subsequent code section references are to the Public Utilities Code unless otherwise indicated.

In this decision, we address the significant modifications in the 2012 RPS Procurement Plans, as compared to the 2011 Plans, presented by PG&E, SCE, and SDG&E, as set forth in the May 23, 2012 draft Plans and updated on August 15, 2012. Generally, these modifications include requests that the Commission accept various revisions to the bid solicitation protocols and the pro forma agreement. Some of PG&E's, SCE's, and SDG&E's proposed revisions are accepted. We accept the modifications pertaining to, for example, standard variables for the Least Cost, Best Fit bid evaluation methodology, contract termination rights based on higher than expected transmission upgrade costs, and the use of energy-only and full deliverability Time of Delivery factors. We also defer consideration on a number of issues related to PG&E's, SCE's, and SDG&E's RPS procurement activities to later in this proceeding.

This decision also accepts the Integrated Resource Plan Off-Year Supplement filed by PacifiCorp, a multi-jurisdictional utility, and the RPS Procurement Plans filed by the small utilities, Bear Valley Electric Service, a Division of Golden State Water Company, and California Pacific Electric Company, LLC. Pursuant to § 365.1(c)(1)[2] and Decision (D.) 11-01-026, this decision accepts for the first time RPS Procurement Plans filed by electric service

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[2] § 365.1 was enacted by Senate Bill 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. § 365.1 expressly exempts community choice aggregators from this requirement.

providers (ESPs).[3] We deem the filings of the ESPs and the smaller utilities as final 2012 RPS Procurement Plans. No further filings are required. No further action is required pertaining to the Integrated Resource Plan filed by PacifiCorp.

This proceeding remains open.

2. Procedural History

The California Renewables Portfolio Standard Program (RPS Program) was established by Senate Bill 1078, effective January 1, 2003 (Sher, Stats. 2002, ch. 516).[4] This legislation established, 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 Legislature accelerated this goal to 20% by 2010 in Senate Bill 107 (Simitian, Stats. 2006, ch. 464). In 2011, Senate Bill 2 1X (Simitian, Stats. 2011, ch. 1) made significant changes to the RPS Program, most notably extending the RPS goals from 20% of retail sales of California's investor-owned utilities (IOUs), electric service providers (ESPs), and community choice aggregators (CCAs) by the end of 2010 to 33% of retail sales of IOUs, ESPs, and CCA and publicly owned utilities by 2020.[5] Senate Bill 2 1X also modified or changed many details

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

[4] The RPS statute is codified at §§ 399.11-399.30.

[5] Senate Bill 2 1X was enacted by the Legislature in 2011 in the 2011-2012 First Extraordinary Session to be effective on December 10, 2011.

of the RPS Program, including creating portfolio content categories for RPS procurement[6] and establishing specific compliance periods for measuring compliance with the 33% goals.[7]

This rulemaking was initiated to, among other things, implement Senate Bill 2 1X and for the continued administration of the RPS Program.[8]

On April 5, 2012, the assigned Commissioner initiated the procurement portion of this proceeding by issuing a ruling in this proceeding, entitled *Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2012 Renewables Portfolio Standard Procurement Plans Pursuant to Public Utilities Code Sections 399.11 et seq. and Requesting Comments on New Proposals* (April 5, 2012 ACR).

The April 5, 2012 ACR directed utilities and ESPs to file RPS Procurement Plans for 2012 on or before May 23, 2012. In accordance with the April 5, 2012 ACR, utilities and ESPs filed their 2012 RPS Procurement Plans describing the actions that would be undertaken to meet the RPS Program procurement requirements. These plans include many aspects, such as compliance with General Order 156 and § 8283, as recently amended by Assembly Bill 1386.[9] Section 8283 is the statutory provision requiring utilities to submit plans for

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[6] D.11-12-052 *Decision Implementing RPS Portfolio Content Categories* 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).

[7] D.11-12-020 *Establishes Procurement Quantity Requirements for Retail Sellers* sets the procurement quantity requirements for the RPS Program.

[8] Rulemaking (R.) 11-05-005, *Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program* at 8. This rulemaking was adopted by the Commission on May 5, 2011.

[9] Assembly Bill 1386 (Bradford, Stats. 2011, ch. 443).

"increasing procurement from women, minority, and disabled veteran business enterprises in all categories, including, but not limited to, renewable energy…."

On August 15, 2012, utilities and ESPs submitted updates to their previously filed plans. The full schedule for the filing of 2012 RPS Procurement Plans and subsequent documents was attached to the April 5, 2012 ACR. The major modifications of the RPS Procurement Plans filed by Pacific Gas and Electric Corporation (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) are described in separate sections of this decision. Additionally, PG&E, SCE, and SDG&E filed Transmission Ranking Cost Reports (TRCRs) on June 27, 2012.[10] TRCRs are used to provide estimated transmission cost data in the Least-Cost, Best-Fit (LCBF) evaluation of bids and by the utilities for the purpose of establishing a relative ranking of bids.[11] No comments were received in response to this filing.

The April 5, 2012 ACR also presented seven proposals for revising the RPS procurement planning and review process. In short, the proposals presented in the ACR included (1) standardized variables in the LCBF bid evaluation methodology; (2) an additional Independent Evaluator report earlier in the procurement review process; (3) relying on the California Independent System Operator (CAISO) transmission cost studies in the LCBF analysis; (4) creating two shortlist of bids based on the status of each project's transmission cost

[10] April 5, 2012 ACR at 12.

[11] In D.04-07-029, *Opinion Adopting Criteria For the Selection of Least-Cost and Best-Fit Renewable Resources* (July 8, 2004). This decision addresses the requirement in the then effective § 399.14(a)(2)(b) which provided, among other things, that the Commission must adopt a process that provides criteria for the rank and ordering and selection of least-cost and best-fit renewable resources on a total cost basis.

studies; (5) bids placed on a shortlist would expire after 12 months; (6) a two-year RPS procurement planning cycle; and (7) placing more emphasis on the Commission's procurement planning as a means of reducing transmission costs. Parties submitted comments on these proposals and we address the merits of these proposals today.

The small utilities filed 2012 RPS Procurement Plans, including Bear Valley Electric Service, a Division of Golden State Water Company (Bear Valley) and California Pacific Electric Company, LLC (CalPeco). These small utilities are subject to a subset of the filing requirements and were not required to respond to the proposals set forth in the April 5, 2012 ACR.[12] PacificCorp, the only multi-jurisdictional IOU, is permitted by statute to file an Integrated Resource Plan which is prepared for regulatory agencies in other states provided that the Integrated Resource Plan complies with the requirements under California law.[13] PacifiCorp filed this document on July 16, 2012.

The following ESPs filed 2012 RPS Procurement Plans: 3 Phases Renewables, Calpine PowerAmerica-CA, LLC, Commerce Energy, Inc., Commercial Energy of California, Consolidated Edison Solutions, Inc., Constellation NewEnergy, Inc., Direct Energy Business, LLC, EDF Industrial Power Services (CA), LLC, EnerCal USA, LLC, Gexa Energy California, LLC, Noble Americas Energy Solutions LLC, Pilot Power Group, Inc., Praxair

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[12] April 5, 2012 ACR at 7 and § 399.18(a)(1).

[13] § 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*.

Plainfield, Inc., Shell Energy North America (US), L.P., Tiger Natural Gas, Inc. The ESPs are subject to a subset of the filing requirements.[14]

Simultaneous with our consideration of the 2012 RPS Procurement Plans, we undertook a review of the renewable net short calculation. The renewable net short (RNS) is defined as the amount of new renewable generation necessary for retail sellers to meet or exceed the renewable procurement quantity requirements. A workshop on this issue was held on June 12, 2012 at which time two preliminary Energy Division RNS proposals were vetted by parties. In response to comments by parties, on July 11, 2012, the assigned Administrative Law Judge (ALJ) issued a ruling which entered Staff's amended RNS proposal into the record of this proceeding and set the date of July 18, 2012 for comments on the amended Staff proposal. The assigned ALJ issued another ruling on August 2, 2012 to enter the final RNS methodology into the record and direct the use of the final RNS methodology in the August 15, 2012 updates to the 2012 RPS Procurement Plans.

This decision also clarifies the scope of the August 2, 2012 ruling. The ruling instructed the utilities to rely upon their own margin of over-procurement for their updated 2012 RPS Procurement Plans as part of the RNS methodology adopted by the August 2, 2012 ruling. The ruling made no finding on the reasonableness of each utility's margin of over-procurement. The ruling also did not address § 399.13(a)(4)(D), the statutory provision relating to minimum margin of procurement above the minimum procurement level necessary to comply with the RPS Program and to mitigate the risk that renewable projects

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[14] April 5, 2012 ACR at 5.

planned or under contract are delayed or canceled. Likewise, the ruling made no finding on the reasonableness of each utility's success rate, which is also incorporated in the RNS methodology adopted by the August 2, 2012 ruling. The Commission will address this statutory provision and the success rates relied upon by the utilities later in this proceeding. As clarified here, we adopt the August 2, 2012 ruling in today's decision.

On August 31, 2012, the assigned ALJ issued a ruling requesting additional information pertaining to SCE's request to not hold a 2012 solicitation. SCE and parties filed responses to this ruling.[15]

On September 12, 2012, the assigned Commissioner issued an *Amended Scoping Memo and Ruling* (Amended Scoping Memo) setting the agenda for the remaining part of this proceeding. This Amended Scoping Memo ruling confirms that setting rules for the RPS Program and developing processes that will enable retail sellers and other RPS market participants to provide the greatest value to ratepayers and all Californians from the RPS Program will continue to be the focus of matters presented in this proceeding going forward. Pursuant to the schedule adopted in the Amended Scoping Memo and as discussed herein, several issues framed for consideration in the April 5, 2012 ACR related to RPS procurement review and reform are deferred to later in this proceeding.

On October 5, 2012, the assigned Commissioner issued a second ruling on procurement reform proposals, *Second Assigned Commissioner's Ruling Issuing*

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15 *Administrative Law Judge's Ruling Requesting Additional Information from Southern California Edison Company Regarding Proposal Not to Hold a 2012 RPS Solicitation* (dated August 31, 2012).

Procurement Reform Proposals and Establishing a Schedule for Comments on Proposal (October 5, 2012 ACR).

This proceeding remains open.

3. Overview of 2012 RPS Procurement Plans Requirement

The 2012 RPS Procurement Plans filed by PG&E, SCE, and SDG&E include a number of components.[16] 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, such as LCBF; (7) estimate of transmission costs for RPS procurement; and (8) cost quantification.[17] The

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[16] For example, PG&E's 2012 RPS Procurement Plans included (1) Quantitative Information at Appendix 1; (2) 2012 RPS Procurement Information Related to Cost Quantification at Appendix 2; (3) Other Modeling Assumptions Incorporated in Quantitative Information at Appendix 3; (4) Status Update on All RPS Resources Under Contract but Not Yet Delivering Generation at Appendix 4; (5) Changes in the 2012 RPS Power Purchase Agreement (PPA); Compared to the Form RPS PPA filed with the California Public Utilities Commission (CPUC or Commission) in May 2012 at Appendix 5; (6) Draft 2012 Solicitation Protocol and Attachments at Appendix 6; (7) Redline of Draft 2012 RPS Solicitation Protocol and Attachments at Appendix 7; and (8) Redline of Draft 2012 RPS Plan at Appendix 8. SCE's and SDG&E's 2012 RPS Procurement Plans include substantially similar information. Some of these documents have been designated confidential according to D.06-06-006, as modified by D.07-05-032 and D.08-04-023, and as affirmed by ALJ ruling dated August 16, 2012. All of these documents are available at the link referred to as the Docket Card on the Commission's website.

[17] § 399.13(a)(5)(A)-(F); D.04-07-029 (setting forth LCBF methodology); D.04-06-013 (adopting Transmission Ranking Cost Report requirement for enabling consideration of transmission cost in the relative ranking of bids in RPS procurement solicitations); SB 836 (Padilla, Stats. 2011, ch. 600, § 1) which imposes new RPS date quantification reports to the legislature.

Commission has established additional requirements and the April 5, 2012 ACR requested specific information for 2012.

Importantly, as set forth in the September 12, 2012 Amended Scoping Memo and October 5, 2012 ACR, certain issues will be addressed by the Commission later in this proceeding, including implementing the statutory requirements set forth in Senate Bill 2 1X for the Commission to establish an RPS procurement expenditure limitation for California electrical corporations.[18]

PG&E, SCE, and SDG&E filed updates to their May 23, 2012 RPS Procurement Plans on August 15, 2012. Other small utilities and ESPs filed updates as well.

SCE's update served to inform the Commission that SCE no longer planned to hold a general 2012 RPS solicitation. Accordingly, SCE withdrew all bid solicitation protocols from its 2012 RPS Procurement Plan, including its 2012 Procurement Protocol and pro forma agreement.[19] We address issues related to these documents in today's decision.

PG&E's and SDG&E's updates contained more recent information to reflect Commission decisions adopted since the original draft 2012 RPS Procurement Plans were filed in May, such as the RPS compliance decision

[18] § 399.15(c)-(g) provides, in part, as follows: "The commission shall establish a limitation for each electrical corporation on the procurement expenditures for all eligible renewable energy resources used to comply with the renewables portfolio standard. In establishing this limitation, the commission shall rely on the following: …."

[19] SCE's updated RPS Procurement Plan, August 15, 2012 at 2.

(D.12-06-038)[20] and the Feed-in Tariff decision (D.12-05-035).[21] PG&E and SDG&E both identified other miscellaneous changes that were made in the updated 2012 RPS Procurement Plans. Some of these issues are addressed in sections 5, 6 and 7 of this.

4. General Issues Related to 2012 RPS Procurement Plans

To the extent the 2012 RPS Procurement Plans filed by PG&E, SDG&E, and SCE raised very similar or the same issues, we address the issues below. We address issues unique to each utility in sections 5, 6 and 7 herein. While SCE will not hold a solicitation in 2012, we still address some of the issues pertaining to SCE's 2012 RPS Procurement Plan and its solicitation protocols to the extent the issues pertain to the other utilities or have broader implications for the RPS Program.

4.1. Imperial Valley

On December 18, 2008, the Commission adopted D.08-12-058, which approved the 500-kilovolt Sunrise Powerlink Transmission Project. The 117-mile Sunrise Powerlink Transmission Project runs from Imperial County to San Diego and was energized on June 18, 2012. We have previously addressed issues related to the Sunrise Powerlink Transmission Project in prior RPS Procurement

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[20] The Commission recently implemented some changes to the rules for retail sellers' compliance with the RPS Program set forth in Senate Bill 2 1X in D.12-06-038, *Decision Setting Compliance Rules for the Renewables Portfolio Standard Program* (June 21, 2012).

[21] The Commission recently adopted modifications to the Feed-in Tariff program when implementing the statutory amendments in Senate Bill 32 and Senate Bill 2 1X in D.12-05-035, *Decision Revising Feed-in Tariff Program, Implementing Amendments to Public Utilities Code Section 399.20 Enacted by Senate Bills 380, Senate Bill 32 and Senate Bill 2 1X* and *Denying Petitions for Modification*.

Plan decisions, and we again address related issues as raised by parties in comments to the utilities' draft RPS Procurement Plans.

4.1.1. Imperial Valley Monitoring and Sunrise Powerlink Transmission Project

In today's decision, we require continued monitoring of the utilities' procurement activities in the Imperial Valley area and renewable projects' utilization of the Sunrise Powerlink Transmission Project. We decline to adopt requests for additional actions to further bolster procurement as the evidence indicates sufficiently robust RPS procurement in that area.

In the Commission's decision accepting of the 2009 RPS Procurement Plans, the Commission stated it would consider requiring so-called "remedial measures" in future RPS Procurement Plans if "evidence shows that the LCBF methodology fails to properly value Imperial Valley resources and their unique access to transmission, or that there are other infirmities [in the RPS procurement in that area]."[22] The Commission has continued to monitor RPS procurement in this area consistent with the terms set forth in Appendix A of D.09-06-018 but has yet to adopt any remedial measures.[23] As stated in D.09-06-018, the purpose of the monitoring is the recognition that "Sunrise is an important project in

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[22] D.09-08-018, *Decision Conditionally Accepting Procurement Plans for 2009 Renewables Portfolio Standard Solicitations and Integrated Resource Plan Supplements* at 17. For more background on the genesis of these remedial measures, refer to the Commission decision approving of the Sunrise Powerlink Transmission Project in D.08-12-058, *Decision Granting a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project* (December 18, 2008).

[23] D.11-04-030, *Decision Conditionally Accepting 2011 Renewables Portfolio Standard Procurement Plans and Integrated Resource Supplements* at 25. In the decision, the Commission reiterated its commitment to consider remedial measures in the future, as needed, but declined to adopt them.

California. It deserves reasonable attention to ensure that it is used efficiently, equitably and wisely." The Commission's commitment to this matter was most recently affirmed in the decision accepting the 2011 RPS Procurement Plans.[24]

In comments to the 2012 draft Procurement Plans, Imperial Irrigation District (IID) claimed that significant barriers to renewable development in the Imperial Valley continue to exist and suggested that the Commission now (and for the first time) adopt remedial measures to bolster the efforts of the utilities to advance meaningful development of new generation in the Imperial Valley and the area interconnected to IID.[25] In addition and regardless of whether the Commission adopts these remedial measures, IID asked the Commission to prohibit overt preferences for projects interconnected to the CAISO. Specifically, IID requested that utilities apply neutral metrics to compare transmission costs for CAISO and non-CAISO interconnected projects and clarify eligibility of non-CAISO projects to engage with projects bidding into RPS solicitations. Center for Energy Efficiency and Renewable Technologies (CEERT), CalEnergy Generation (CalEnergy), Solar Reserve and 8minutenergy Renewable, LLC (8minutenergy) generally agreed with IID. All these parties also pointed out that little to no information regarding procurement in this area was included in the 2012 draft Procurement Plans filed by PG&E, SCE, and SDG&E.

In response to these parties' concerns, SDG&E noted that it remains committed to the development of renewable resources in the Imperial Valley

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[24] The Commission addressed Imperial Valley in D.11-04-030, *Decision Conditionally Accepting 2011 Renewables Portfolio Standard Procurement Plans and Integrated Resource Supplements*.

[25] IID comments, June 27, 2012 at 6.

region.[26] To illustrate its commitment, SDG&E stated that it maintains an office in the region to serve as an information center for potential renewable developers and, as of June 2012, SDG&E has approximately 3,400 gigawatt hour (GWh) under contract from projects that will be facilitated by the Sunrise Powerlink Transmission Project. The below table lists Commission-approved contracts submitted by SDG&E for projects in the Imperial Valley and eastern San Diego County area.

SDG&E's Commission-approved RPS Contracts

Campo Verde	Imperial	Solar PV	123	304
Centinela Solar Energy	Imperial	Solar PV	110	235
Centinela Solar Energy 2 (Expansion)	Imperial	Solar PV	30	62
CSolar IV South (Tenaska I)	Imperial	Solar PV	97	204
Pattern Energy Group - Ocotillo Express Wind Project	Imperial	Wind	265	891
Sempra Generation-Energia Sierra Juarez I - Jacume	Baja, MX	Wind	100	324
CSolar IV West (Tenaska II)	Imperial	Solar PV	96	264
Mt. Signal I Solar Farm	Imperial	Solar PV	150	495
Soitec (5 PPAs)	San Diego	Solar CPV	114	280
SolarGen 2	Imperial	Solar PV	150	390

Provided that all of the projects listed in the table achieve commercial operation, SDG&E will likely have fulfilled its Sunrise renewables commitment provided for in D.08-12-058. In order to account for potential project failure and ensure achievement of its Sunrise commitment, SDG&E asserted that it continues to consider contracting with projects located in the Imperial Valley region.

Likewise, PG&E pointed to the robustness of the bid response in the 2009 and 2011 RPS solicitations, as captured in the Independent Evaluator

[26] SDG&E reply comments, July 18, 2012 at 17.

report,[27] from projects located in the Imperial Valley as evidence that no further special measures are needed in this area to support RPS procurement.[28] SCE provided a similar statement noting that its experience shows that Imperial Valley sellers are aware of the RPS solicitation process and that its bid evaluation criteria considers the benefit of projects being located near approved transmission infrastructure, such as the Sunrise Powerlink Transmission Project.[29]

In today's decision, we affirm the Commission's commitment to continue monitoring renewable procurement activities in Imperial Valley. We decline, however, to adopt the requests for additional oversight mechanisms based on, among other things, the continued robust procurement in the area, as indicated by the amount of capacity currently under contract in the Imperial Valley region and the robust interest for project development based on the results of prior solicitations and the Independent Evaluator's report. At this time, we do not find that additional support for RPS procurement in this area is required. In addition, a special Imperial Valley Bidder's conference is optional for the utilities and we will not require it due to a lack of interest in such an event in the past and the confusion created by the presumed preferential treatment that holding

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[27] PG&E reply comments, July 18, 2012 at 22, *citing to* Arroyo Seco Consulting, "Report of the Independent Evaluator on the Offer Evaluation and Selection Process," PG&E 2011 RPS Solicitation Shortlist, Advice Letter 3938-E, November 7, 2011 at 15-16, 55.

[28] PG&E reply comments July 18, 2012 at 23.

[29] SCE reply comments July 18, 2012 at 14.

such an event created.[30] We agree with IID and others that further information could have been provided regarding RPS procurement activities in this area in the 2012 Procurement Plan and direct utilities to provide such information in future plans.

In response to the topic raised by IID about the possibility of preferences for CAISO-interconnected projects, PG&E suggested that the Commission clarify that no preferences are given to CAISO-interconnected projects or to projects otherwise interconnected.[31] The Commission agrees with PG&E that no preferences should be given to CAISO-interconnected projects or to projects otherwise interconnected.

Accordingly, the Commission's Energy Division Staff is directed to continue to monitor RPS development in the Imperial Valley according to the parameters set forth in Appendix A of D.09-06-018. In addition, PG&E, SCE, and SDG&E are directed to 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.

4.1.2. Imperial Valley District Balancing Authority Area and Maximum Import Capability

In today's decision, we clarify that, PG&E, SCE, and SDG&E should assume a maximum import capability (MIC) of no less than 1,400 megawatts (MW) for imports from the Imperial Irrigation District Balancing Authority Area

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[30] SCE reply comments, July 18, 2012 at 14-15, stating that prior to holding an Imperial Valley Bidders' Conference in 2009 "SCE received numerous questions from confused sellers about the purpose and goal of a separate conference for the Imperial Valley."

[31] PG&E reply comments, July 18, 2012 at 17.

to the CAISO Balancing Authority Area as part of the evaluation of projects and bids within the 2012 RPS solicitation.[32] Additionally, if PG&E, SCE, or SDG&E assigns zero or near zero resource adequacy value to any project located in the Imperial Irrigation District Balancing Authority Area that bids in the 2012 RPS solicitation, that utility must present clear and convincing evidence why it did so as part of each request seeking Commission approval of any contract resulting from the 2012 RPS solicitation.

On June 7, 2011, an assigned Commissioner's ruling ordered PG&E, SCE, and SDG&E to assume a MIC of no less than 1,400 MW for imports from within the Imperial Irrigation District Balancing Authority Area to the CAISO Balancing Authority Area as part of the evaluation of projects and bids within the 2011 Renewables Portfolio Standard solicitation. More recently, the CAISO modified its Reliability Requirements Business Practice Manual regarding the calculation of the MIC, including at the Imperial Valley intertie between the Imperial Irrigation District and CAISO balancing areas. In comments on the draft 2012 RPS Procurement Plans, CalEnergy, IID, and SolarReserve recommended that the Commission retain the requirement in the June 7, 2011 assigned Commissioner's ruling for the purposes of calculating resource adequacy benefits in the 2012 RPS solicitation bid evaluations.[33]

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[32] The maximum import capability is calculated annually by the California Independent System Operator (CAISO). It is the maximum megawatt amount of import capacity that will be available to CAISO load-serving entities (LSEs) for procuring resources outside the ISO balancing authority area (BAA) to meet their resource adequacy requirements for the coming year.

[33] CalEnergy comments, June 27, 2012 at 9; IID comments, June 27, 2012 at 22; SolarReserve comments, June 27, 2012 at 15.

In response, PG&E noted that its proposed LCBF methodology does not assume any constraint on resource adequacy-qualifying import capacity from the IID balancing authority into CAISO. SCE and SDG&E voiced similar concerns and, in addition, pointed to a number of complications that could result from such a requirement.[34] Specifically, SCE commented that, if the utilities each assume a MIC of 1,400 MW from the Imperial Valley, when in reality, that MIC is allocated between CAISO-connected utilities based on a statewide percentage of California load share, utilities are likely to over-value imports from IID.

We agree that, were a utility to contract for energy and resource adequacy from an IID-located project based on this erroneous assumption, it would then face the very real risk that the CAISO would allocate it less import capability than the amount set forth in the contract due to the demand among other LSEs for import capability. Moreover, requiring the utilities to each use a 1,400 MW MIC value for projects in the IID area also leads to equity concerns regarding bids at other interties. However, consistent with the June 7, 2011 ACR, the utilities should assume a total MIC of no less than 1,400 MW for import from within the IID Balancing Authority Area as part of the evaluation of bids.

Accordingly, PG&E, SCE, and SDG&E should assume a maximum import capability of no less than 1,400 MW for imports from projects within the Imperial Irrigation District Balancing Authority Area to the CAISO Balancing Authority Area as part of the evaluation of projects and bids within the 2012 RPS solicitation. Additionally, if PG&E, SCE, or SDG&E, nevertheless, assign zero or near zero resource adequacy value to any project located in the Imperial

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[34] SCE reply comments July 18, 2012 at 15.

Irrigation District Balancing Authority Area that bids in the 2012 RPS solicitation, that utility must present clear and convincing evidence why it did so as part of each request seeking Commission approval of any contract resulting from the 2012 RPS solicitation. This directive applies to future RPS Procurement Plans filed by PG&E, SCE, and SDG&E unless otherwise directed by the Commission.

4.2. Modifications to the RPS Bid Solicitation Protocols

On May 23, 2012, pursuant to § 399.13(a)(5)(C) and in response to the April 5, 2012 ACR, PG&E, SCE, and SDG&E submitted solicitation protocols as part of their draft 2012 RPS Procurement Plans. These solicitation protocols 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. SCE's updated 2012 RPS Procurement Plan served to inform the Commission that it no longer planned to hold a general 2012 RPS solicitation. SCE, accordingly, removed all bid solicitation materials from its 2012 RPS Procurement Plan. While this decision accepts SCE's proposal to not hold a 2012 RPS solicitation (see section 6.1 herein), we address issues related to its solicitation protocols to the extent the issues pertain to PG&E and SDG&E or have broader implications.

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' unmet need for eligible RPS resources and desired deliverability characteristics of those resources, such as, online date and locational preferences, and other statutory or Commission-mandated requirements.

In contrast to the 2011 bid solicitation protocols, the 2012 bid solicitation materials include several new protocols, including (1) preferences for when deliveries would start; (2) contract term lengths; (3) project locations; and (4) preferences for specific compliance periods and portfolio content category classification as set forth in Senate Bill 2 1X.[35] A proposal regarding the use of integration costs in LCBF was also submitted. These modifications and the extent to which we accept these modifications are addressed below. The utilities are charged with the responsibility of identifying significant modifications in the 2012 RPS Procurement Plans. To the extent the utilities failed to identify a significant modification, the matter is not addressed below and, therefore, not accepted today.

4.2.1. Stated Preferences for Specific RPS Resources

In today's decision, we accept the proposal by PG&E and SDG&E to include the varying preferences set forth in their 2012 RPS Procurement Plans, such as project location, delivery start dates, term lengths, and specific portfolio content categories in the 2012 bid solicitation protocols.

Parties presented certain concerns regarding the utilities' newly stated RPS solicitation preferences on the basis of fairness and consistency with RPS Program's policies and rules. Independent Energy Producers Association (IEP) recommended that SCE be directed to allow RPS-eligible products of any

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[35] Portfolio content categories for the RPS Program are set forth in § 399.16 and were added to the statute by Senate Bill 2 1X in 2011. The Commission defined and implemented these code provisions in D.11-12-052, *Decision Implementing Portfolio Content Categories for the Renewables Portfolio Standard Program* (December 15, 2011).

portfolio content category to compete in its RPS solicitation.[36] DRA expressed concern regarding SCE's exclusion of portfolio content Category 2 and 3 products in its bid solicitation materials.[37] CEERT similarly questioned the merit of restricting or having preferences for certain portfolio content categories and stated that such preferences inappropriately limit competition.[38] Additionally, SolarReserve, LLC (SolarReserve) recommended that utilities be ordered to eliminate any preferences for projects that will be interconnecting in the CAISO balancing authority area.[39]

In response, PG&E and SCE disagreed with parties' above-noted concerns that utility preferences for certain portfolios content categories, project locations, and delivery start dates are inconsistent with RPS policy and program requirements.[40] The Utility Reform Network (TURN) additionally commented that preferences for certain portfolio content categories and project location are not contrary to the RPS Program requirements.[41]

We agree with TURN that the preferences are not contrary to the requirements of the RPS Program. As TURN comments, the RPS Program does not, for example, require the procurement of products from all three portfolio content categories. We find it reasonable for the utilities to solicit offers based on

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[36] IEP comments, June 27, 2012 at 14.

[37] DRA comments, June 27, 2012 at 5.

[38] CEERT comments, June 27, 2012 at 14.

[39] SolarReserve comments, June 27, 2012 at 5.

[40] PG&E reply comments, July 18, 2012 at 11 and SCE reply comments, July 18, 2012 at 6.

[41] TURN reply comments, July 18, 2012 at 1.

the various preferences set forth in their 2012 RPS Procurement Plans. In comments to the proposed decision, CEERT claimed that bid solicitation preferences are analogous to so-called "carve-outs." We disagree. The terms "carve-outs" refers to preferences that could be established by the Commission which would require the utilities to purchase specific types of renewable generation, such as bioenergy. Bid solicitation preferences are criteria established by the utility as a means of meeting unmet renewable generation needs and legal requirements under the RPS Program.

Accordingly, in the final 2012 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E and SDG&E are authorized to include the varying preferences set forth in their 2012 RPS Procurement Plans, including, but not limited to, project location, delivery start dates, contract term lengths, and specific portfolio content categories. This authorization applies to future RPS Procurement Plans filed by PG&E and SDG&E unless otherwise directed by the Commission. While SCE will not hold a 2012 solicitation, this authorization shall apply to its future RPS Procurement Plans unless otherwise directed.

4.2.2. Standard Variables for Net Market Valuation

This decision adopts the proposal presented in the April 5, 2012 ACR to standardize the variables to be included in the NMV calculation. The NMV calculation is a part of the utilities' LCBF methodologies. We make no determination in today's decision on how each utility should value those NMV variables, except as noted in sections 4.2.3 (Integration Cost Adders) and 4.4.1 (Transmission Study Status: Impact on Bid Evaluation and Shortlist).

Consistent with the proposal in the April 5, 2012 ACR, the NMV should be calculated as follows:

Net Market Value: R = (E + C) – (P + T + G + I)
Adjusted Net Market Value: A = R + S

Where:[42]
R = Net Market Value
A = Adjusted Net Market Value
E = Energy Value
C = Capacity Value
P = Post-Time-of-Delivery Adjusted Power Purchase Agreement Price
T = Transmission Network Upgrade Costs
G = Congestion Costs
I = Integration Costs
S = Ancillary Services Value[43]

The goal of the proposal presented in the April 5, 2012 ACR was to increase transparency in the LCBF evaluation process and streamline review of bid solicitations and contracts by establishing a standardized set of values and costs to be incorporated into the net market value portion of the utilities' LCBF methodologies. Standardization will better promote comparison between the utilities.

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42 All units are in dollars per megawatt hour.

43 The term "ancillary services" as defined by Federal Energy Regulatory Commission (FERC) in 75 FERC ¶ 61,080 (1996) are those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system. In Order 888, FERC defined six ancillary services: (1) scheduling, system control and dispatch; (2) reactive supply and voltage control from generation service; (3) regulation and frequency response service; (4) energy imbalance service; (5) operating reserve – synchronized reserve service; and (6) operating reserve – supplemental reserve service.

Parties generally supported the variables included in the proposed NMV calculation. EnergySource LLC (EnergySource), IEP, Ormat Technologies, Inc. (Ormat), Sierra Club California (Sierra Club), and SCE recommended additional variables, including environmental benefits, such as including greenhouse gas reductions and fossil fuel displacement, job creation benefits, tax benefits, tax revenues, curtailment, and also debt equivalence.[44] PG&E recommended that the congestion costs (variable G) not be included in the NMV calculation as a stand-alone variable but instead be incorporated into the variables described as energy value (variable E) and capacity value (variable C). Also, while most parties were supportive of including integration costs (variable I) in the NMV calculation, they recommended the value of the variable be developed in a public process, such as a Commission proceeding.[45] Additionally, several parties commented on the desire for more transparency in the valuations of the variables of the NMV calculation.[46]

In response to PG&E's recommendation, we look for guidance to the Commission decision accepting the 2011 RPS Procurement Plans, D.11-04-030. In

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[44] EnergySource comments, June 27, 2012 at 5; IEP comments, June 27, 2012 at 18; Ormat comments, June 27, 2012 at 3; and Sierra Club comments, June 27, 2012 at 2.

[45] BrightSource comments, June 27, 2012 at 5; California Wind Energy Association (CalWEA) comments, June 27, 2012 at 12; CEERT comments, June 27, 2012 at 22; IEP comments, June 27, 2012 at 14; Large-scale Solar Association's (LSA's) reply comments, July 18, 2012 at 7; TURN comments, July 18, 2012 at 2. The LSA's members include Ausra, Inc., Abengoa, Inc., BrightSource Energy, Inc., First Solar, Inc., Infinia Corp., Optisolar, Inc., Solel Inc., SunPower, Corp., Iberdola Renewables and Stirling Energy Systems.

[46] Capital Power Corporation (Capital Power) comments, June 27, 2012 at 3; CalEnergy comments, June 27, 2012 at 18; City and County of San Francisco comments, June 27, 2012 at 4; TransWest Express LLC (TransWest) comments, June 27, 2012 at 2.

that decision, we ordered utilities to include congestion costs as part of their evaluation of bids in manner that was clear and transparent.[47] Today, in furtherance of the Commission's goals of transparency and standardization, we find it reasonable to keep the variable of congestion costs as a separate variable.

In response to the new variables suggested by parties, we find that the addition of these variables to the NMV calculation could potentially add to the robustness of the calculation but that sufficient evidence does not exist presently for determining whether these additional variables should be more appropriately included as part of the NMV calculation or as a separate aspect of the utilities' LCBF evaluations. Other questions remain regarding these additional variables and how they would implemented in a reasonable and transparent manner. Therefore, consistent with previous Commission decisions, the NMV calculation variables, as set forth above, are reasonable, and we adopt the April 5, 2012 ACR proposal without modifications.[48]

Except as noted in sections 4.2.3 and 4.4.1 herein, we make no determination at this time regarding how the values of the variables should be calculated. In sections 4.2.3 and 4.4.1 of today's decision, we address the requests by some parties to adopt a value for the integration variable and a methodology for calculating the transmission variable.

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[47] D.11-04-030, *Decision Conditionally Accepting 2011 Renewables Portfolio Standard Procurement Plans and Integrated Resource Supplements* at 19.

[48] In D.04-07-029, which established LCBF bid ranking criteria, the Commission adopted criteria for the LCBF selection of RPS-eligible resources. Additionally, in D.11-04-030, *Decision Conditionally Accepting 2011 Renewables Portfolio Standard Procurement Plans and Integrated Resource Supplements*, the Commission addressed the inclusion of congestion costs in the utilities' LCBF evaluations.

Accordingly, in the final 2012 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E and SDG&E shall modify their LCBF methodologies to reflect the NMV calculation set forth above. This directive applies to future RPS Procurement Plans filed by PG&E and SDG&E unless otherwise directed by the Commission. We authorize the Commission's Energy Division Staff to propose modifications to the inputs to the NMV calculation through the Commission Resolution process. This methodology shall also be employed by SCE in future RPS Procurement Plans unless otherwise directed by the Commission.

4.2.3. Integration Cost Adders

In this decision, we decline to accept SCE's and PG&E's request to use non-zero integration cost adders as part of their LCBF evaluation of bids in the 2012 RPS Procurement Plans.[49]

SCE and PG&E proposed the use of non-zero integration cost adders in their draft 2012 RPS Procurement Plans as part of their LCBF evaluation of bids. The function of this adder would be to estimate the cost to ratepayers for the real time balancing of the transmission system from instability caused by unexpected fluctuations in generation or load caused by the project. Thus, each bid would be assessed an integration adder to estimate the cost to integrate the project into the transmission system. More specifically, PG&E proposed the use of an integration cost adder of $7.50/MWh (2008$) (approximately $8.50/MWh (2013$)) based on the value used in the standard planning assumptions of the

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[49] The term "non-zero" means any value above zero.

2010 Long-Term Procurement Planning proceeding.[50] PG&E argued that the assumption of an integration cost of zero is not reasonable because, as various parties noted, there have been studies and various efforts to determine the cost to integrate renewables.[51] PG&E asserted that, therefore, the Commission should establish a value for an integration adder, even if the adopted value is preliminary, for use in the bid solicitation evaluation process, which is the process by which the utilities estimate value projects to ratepayers.

As DRA noted, we have previously rejected proposals for non-zero integration cost adders and have reasoned that before an integration cost adder is used, it needs to be developed with public review and comment.[52] DRA additionally noted that the value that PG&E proposes was developed by a consultant for modeling purposes in the absence of a rigorous analysis of integration costs. BrightSource Energy, Inc. (BrightSource), CalWEA, CEERT, IEP, LSA, and TURN additionally argued that an integration cost adder should only be used if developed in a public forum.

We agree. Nothing presented in this proceeding has persuaded us to change our view on this matter. Moreover, integration cost adders are included as an element that will be reviewed when we examine LCBF methodologies later in this proceeding. However, an integration cost adder must first be developed

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[50] PG&E's updated 2012 RPS Procurement Plan, August 15, 2012 at 66.

[51] PG&E reply comments, July 18, 2012 at 15.

[52] D.07-02-011, which accepts RPS Procurement Plans for the 2007 RPS solicitations, at 56; D.08-02-008, *Opinion Conditionally Accepting Procurement Plans for 2008 RPS Solicitations* (February 2, 2008) at 44; and D.11-04-030, *Decision Conditionally Accepting 2011 Renewables Portfolio Standard Procurement Plans and Integrated Resource Supplements* at 23.

and based on system–wide impacts. In considering an appropriate integration cost adder, not only should costs to integrate renewable be considered but ways to minimize costs should also be considered. Parties are encouraged to participate in the CAISO processes on this topic or in Commission proceedings, R.12-03-014[53] and this proceeding, to provide data and cost information to develop a robust and meaningful integration cost adder. If an integration cost adder is developed through one of the above mentioned public processes, then each utility may seek authority, consistent with any directives in R.12-03-014 or this proceeding, to amend its 2012 RPS Procurement Plan for the purpose of using that integration cost adder in its NMV calculations and LCBF evaluations.

Accordingly, in the final 2012 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E and SDG&E are not authorized to include language that refers to the use of non-zero integration cost adders, including any language in the NMV portion of their LCBF evaluation methodologies. This directive applies to future RPS Procurement Plans filed by PG&E and SDG&E unless otherwise directed by the Commission. This directive shall also apply to SCE in any future RPS Procurement Plan unless otherwise directed by the Commission.

4.3. Proposals to Change Terms in the Pro Forma Agreement

Pro forma agreements were included as part PG&E's, SCE's, and SDG&E's draft 2012 bid solicitation protocols of May 23, 2012. The pro forma agreements serve as the starting point for negotiating a final agreement between a seller and

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[53] R.12-03-014 *Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans* dated March 22, 2012.

utility.[54] The negotiable quality of most of the terms of the pro forma agreements is in contrast to the so-called standard contracts in, for example, the § 399.20 Feed-in-Tariff[55] and Renewable Auction Mechanism programs.[56] In these programs, the contracts are non-negotiable and the terms are pre-approved by the Commission with the goal of creating a more expedited contracting process. While we consider some of the issues raised by parties with regards to the utilities' proposed modifications to pro forma agreements in the following sections of this decision, the Commission prefers, in most instances, that the parties negotiate contract terms. The Commission will review the resulting executed contracts (upon submission to the Commission for approval) in their totality. Such review may include the terms of the pro forma agreement addressed below, consistency with Commission decisions, cost reasonableness, and fair allocation of risk to the seller, buyer, and ratepayer.

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[54] All terms and conditions in the pro forma agreement are negotiable except for the "standard terms and conditions," as set forth in D.08-04-009, D.08-08-028, and D.10-03-021, as modified by D.11-01-025.

[55] The Commission recently adopted modifications to the Feed-in Tariff program when implementing the statutory amendments in Senate Bill 32 and Senate Bill 2 1X in D.12-05-035, *Decision Revising Feed-in Tariff Program, Implementing Amendments to Public Utilities Code Section 399.20 Enacted by Senate Bill 380, Senate Bill 32 and Senate Bill 2 1X* and *Denying Petitions for Modification*.

[56] The Renewable Auction Mechanism (RAM) program was created by the Commission in D.10-12-048.

4.3.1. Contract Termination Rights based on Transmission Upgrade Costs

In this decision we accept the use of new terms in SCE's and SDG&E's pro forma agreement to allow for contract termination based on transmission upgrade costs.

SCE proposed a modification to its pro forma agreement to provide SCE with termination rights in the event that the results of any interconnection study or agreement indicate that network upgrade costs will exceed a specified amount agreed on between the seller and SCE. This proposal is referred to as a "transmission upgrade cost cap." SCE also proposed that a seller may buy-down the transmission costs that exceed the cap in lieu of contract termination. This means, for example, that the seller has the opportunity to avoid contract termination, if transmission costs exceed the negotiated cap, by agreeing to pay for the costs in excess of the cap without having ratepayers refund those monies, as is current practice. SDG&E similarly included terms in its pro forma agreement that allow for termination if transmission upgrade costs are higher than the threshold agreed to in the executed contract.

In comments filed on the draft 2012 RPS Plans, IEP recommended rejecting SCE's and SDG&E's proposed terms. IEP argued that the proposed terms are unreasonable because transmission network upgrades benefit the entire transmission system. According to IEP, it is unfair to place the transmission network costs entirely on the seller because transmission upgrade costs are outside the control of the developer.[57] City and County of San Francisco, SCE,

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[57] IEP comments, June 27, 2012 at 14 and 18.

and SDG&E opposed IEP's position.[58] SCE argued it is both prudent and reasonable to place a cap on ratepayers' exposure to excessive upgrade costs under a contract. SCE and SDG&E further asserted that limiting the transmission network upgrade costs can ensure the value of the contract to ratepayers as it was originally evaluated during the LCBF process. SCE additionally explained that if the transmission network upgrade costs exceed the negotiated cap, then the project may no longer be as competitive from a value and cost perspective.

We agree with City and County of San Francisco, SCE, and SDG&E that this new term represents a reasonable means of seeking to limit the total RPS procurement costs to ratepayers by linking termination rights to caps on transmission network upgrade costs. Bids are selected and contracts are executed based on their value relative to other offers and opportunities. Transmission costs are an integral part of that valuation. As SCE and SDG&E state, the value of the contract to the ratepayer changes if the transmission upgrade costs exceed caps. SCE's proposal to buy-down the transmission costs that exceed the cap essentially allows the total value of the contract to the ratepayer to remain consistent with the value of the bid and executed contract by placing responsibility for the costs above the cap on the seller. Because this proposal keeps the total expected ratepayer's costs unchanged, we find it reasonable and apply it to PG&E as well.

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[58] City and County of San Francisco reply comments, July 18, 2012 at 2; SCE reply comments, July 18, 2012 at 7; SDG&E reply comments at 11.

Accordingly, in the final 2012 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, SDG&E and PG&E shall incorporate terms into their respective pro forma agreements regarding termination rights and buy-down provisions in the event that the results of any interconnection study or agreement indicate that network upgrade costs will exceed a specific amount agreed to by the seller and the utility. Any costs in excess of the agreed upon amount shall not be imposed on ratepayers. This directive applies to future pro forma agreements filed by PG&E and SDG&E unless otherwise directed by the Commission. While SCE will not hold a 2012 solicitation, this requirement shall apply to future use of its pro forma agreement unless otherwise directed by the Commission.

4.3.2. Limit Contract Negotiation Period: 12-Month Shortlist

In this decision, we adopt the proposal presented in the April 5, 2012 ACR requiring utilities' shortlists to expire 12 months after submitted to the Commission pursuant to the schedule adopted herein.[59] This 12-month period starts on the day the shortlist is submitted to the Commission via advice letter consistent with the schedule adopted herein.

The April 5, 2012 ACR presented a proposal that bids shortlisted by the utilities would have to be executed within 12 months from the date that the utility submits its final shortlist to the Commission.[60] The proposal presented in

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[59] The term "shortlisted" means that the bid is selected for possible contract negotiation which may result in an executed contract.

[60] The shortlist is not approved by the Commission at this submission. The shortlist is approved later when the utility submits a report on the solicitation with an Independent Evaluator report to the Commission as a Tier 2 Advice Letter. Some of the prior Advice

Footnote continued on next page

the April 5, 2012 ACR further stated that if the deadline is not met, then the utility is not permitted to subsequently execute a contract for the same project as a bilateral contract but the project may be bid into the next RPS solicitation.

Several parties expressed opposition and concern regarding the proposal to limit the negotiation period by setting an expiration date on the shortlisted solicitation bids.[61] Parties opposed the option set forth in the proposal that "expired" bids participate in subsequent solicitations based on the concern that this could further delay projects, especially if RPS solicitations were not offered annually. SCE stated that the proposal was unnecessary as sufficient incentives already existed to promote the timely execution of contracts.[62]

SDG&E, Tenaska Solar Ventures (Tenaska), and Sierra Club supported the proposal. Both Tenaska and Sierra Club argued that the proposal would ensure that stale bid data was not relied upon for determining reasonableness of a proposed contract's price and value. Sierra Club additionally commented that the proposal would allow for a more current examination of the most competitive options at the time of contract execution.[63]

Letters include PG&E AL 3938-E, SCE AL 2650-E, and SDG&E AL 2300-E. This 12-month period starts on the day the shortlist is submitted to the Commission via advice letter.

[61] CalWEA comments, June 27, 2012 at 6; CEERT comments, June 27, 2012 at 29; IEP comments, June 27, 2012 at 21; LSA reply comments July 18, 2012 at 2; PG&E 2012 RPS Procurement Plan, August 15, 2012 at 71; SCE comments, May 23, 2012 at 8; and TransWest comments, June 27, 2012 at 6; Zephyr Power Transmission and Pathfinder Renewable Wind Energy (Zephyr/Pathfinder) comments, June 27, 2012 at 5.

[62] SCE comments, July 23, 2012 at 8.

[63] Sierra Club reply comments, June 27, 2012 at 4.

We find that the benefits of being able to compare a contract's value and price to current solicitation data outweighs the concerns regarding the constraints that a limited negotiation period might have on project schedules. Additionally, given the several years of experience that the utilities and sellers have with the RPS Program, RPS contracting process, and the renewable energy project development process, we find it reasonable to expect that contracts can be executed within 12 months. For instance, SDG&E was able to execute six contracts from its 2011 solicitation in less than 10 months.[64]

Additionally, to guard against any misuse of the 12-month time frame as a means to avoid executing a contract, we expect, as is the current practice, that the Independent Evaluator shall raise any issues of any utility's exhibiting a lack of "good faith" during negotiations in the Independent Evaluator's reports or directly with Energy Division Staff.

Accordingly, beginning with the final 2012 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, bids 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. This expiration date is included in the schedule adopted herein. If that deadline is not met, the bid will be removed from the shortlist and the utility will not be permitted to execute a contract for the same project as a bilateral contract until after the initiation of a subsequent RPS solicitation. The project may be bid into the next RPS solicitation. This directive applies to future RPS solicitations by PG&E and SDG&E unless otherwise directed by the Commission.

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[64] SDG&E RPS Project Development Status Report, August 1, 2012.

While SCE will not hold a 2012 solicitation, this requirement will apply to future solicitations until otherwise directed by the Commission.

4.3.3. Energy-Only and Full Capacity Deliverability Time-of-Delivery Factors

In this decision, we accept the request by PG&E, SCE, and SDG&E to use new energy-only and full capacity deliverability Time-of-Delivery (TOD) Factors for the 2012 solicitation.

TOD Factors are applied to contract prices to reflect the higher value of generation supplied during the on-peak hours and the lower value of generation supplied during the off-peak hours. They are applied in both the LCBF evaluation process as well as to contract prices to determine the revenues that a seller will receive for its product. In D.05-12-042, we adopted a recommendation to approve utilities' TOD Factors during the review of utilities' RPS Procurement Plans and proposed Request for Offers (RFOs).[65] We also have previously authorized PG&E, SCE, and SDG&E to develop their own TOD Factors.[66]

PG&E, SCE, and SDG&E each proposed the use of two sets of TOD Factors, energy-only and fully deliverable, in their 2012 RPS solicitation protocols.[67] Under the proposal, the energy-only TOD Factors will be applied during the bid evaluation process to those projects interconnecting as

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[65] D.05-12-042 *Interim Opinion Adopting Methodology for 2005 Market Price Referent* (December 15, 2005) at 21-22.

[66] D.05-12-042, *Interim Opinion Adopting Methodology for 2005 Market Price Referent* (December 15, 2005) at 53.

[67] PG&E draft 2012 RPS Plan, 2012 Solicitation Protocol, May 23, 2012 at 21; SCE draft 2012 RPS Plan, May 23, 2012 at 31; SDG&E updated 2012 RPS Plan, August 15, 2012 Amended Appendix C at 3.

energy-only. The fully deliverable TOD Factors will be applied to projects interconnecting as fully deliverable (full capacity deliverability status).

In response to the proposed TOD Factors, LSA raised a concern regarding the appropriateness of modifying TOD Factors based on the evidentiary record in this proceeding. While LSA acknowledged the appropriateness of having two sets of TOD Factors, it suggested that the TOD Factors proposed by SCE and PG&E are considerably different than those factors used in the 2011 and earlier RPS solicitations. LSA, therefore, recommended that utilities continue to use the TOD Factors used in prior Commission-authorized procurement plans until changes to PG&E's and SCE's TOD Factors are fully vetted.[68] SCE recommended rejection of LSA's proposal to rely on previously approved TOD Factors because the proposed TOD Factors are more appropriately adjusted to reflect current market conditions as they include updated forecasts for energy and capacity.[69]

We adopt the utilities' request to rely on two different sets of new TOD Factors. In the Commission's decision accepting the 2011 RPS Procurement Plans, D.11-04-030, the Commission directed utilities to not require bids to be fully deliverable. In other words, energy-only bids were permissible. Consequently, the Commission will follow this same rule today and, accordingly, in response to the 2012 solicitations, PG&E's and SDG&E's solicitation protocols must accommodate bids that are energy-only or fully deliverable. Because utilities are permitted to receive these two types of bids, we find it reasonable for the utilities to apply different sets of TOD Factors to these

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[68] LSA comments, June 27, 2012 at 9.

[69] SCE reply comments, July 18, 2012 at 22.

two types of bids based on the manner the project will interconnect and provide energy.

We have previously examined the reasonableness of TOD Factors.[70] Similar to these prior Commission findings, today we conclude that PG&E's and SCE's approach and the recommended new TOD Factors are reasonable, even if the TOD factors are different than the TOD Factors applied in 2011 or previous years. We have found previously that each utility may develop its own TOD Factors to best reflect each utility's market-based valuation of electricity and capacity in different time periods.[71] In previous decisions, the Commission has stated that we expect TOD Factors to "recognize the extent of the need for additional capacity."[72] We continue this approach and, we decline to adopt a uniform method or benchmarking system.

However, in an effort to response to concerns expressed by LSA, we are receptive to examining the methodologies used to derive the TOD Factors in a subsequent part of this proceeding. In support of our further consideration of TOD Factors, the September 12, 2012 Amended Scoping Memo and October 5, 2012 ACR include this issue as part of the review of LCBF. Additionally, our

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[70] D.09-06-018, *Decision Conditionally Accepting Procurement Plans for 2009 Renewables Portfolio Standard Solicitations and Integrated Resource Plan Supplements* at 46 and D.06-05-039 *Opinion Conditionally Approving Procurement Plans for 2006 RPS Solicitations, Addressing TOD Benchmarking Methodology and Closing Proceeding* at 68; D.05-12-042, *Interim Opinion Adopting Methodology for 2005 Market Price Referent* (December 15, 2005) at 21-22.

[71] D.06-05-039, *Opinion Conditionally Approving Procurement Plans for 2006 RPS Solicitations, Addressing TOD Benchmarking Methodology and Closing Proceeding* at 68.

[72] D.06-05-039, *Opinion Conditionally Approving Procurement Plans for 2006 RPS Solicitations, Addressing TOD Benchmarking Methodology and Closing Proceeding* at 69.

expectation is that the Commission's authorization of need for additional capacity in any future long-term procurement plan in R.12-03-014[73] is not limited to the calculation of TOD Factors in the RPS proceeding and should be incorporated where appropriate, including in the LCBF methodology.

Accordingly, in the final 2012 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, bids shortlisted by PG&E and SDG&E are authorized to use in their 2012 RPS solicitation two sets of TOD Factors to reflect energy-only and fully deliverable status. This authorization only applies to the 2012 solicitation.

4.4. 2012 RPS Procurement Plans - Solicitation Bid Requirements

The utilities were directed in the April 5, 2012 ACR, pursuant to § 399.13(a)(5)(C), to include bid solicitation protocols that specify what quantity of products are being requested, deliverability characteristics, required online dates, term lengths, and locational preferences. The utilities requested various modifications to their 2012 solicitation protocols as compared to their 2011 solicitation protocols. The April 5, 2012 ACR also included proposals related to the utilities' bid solicitation protocols. These modifications and proposals are addressed below.

4.4.1. Transmission Study Status: Impact on Bid Evaluation and Shortlist

In this decision, we adopt, with the modifications discussed herein, the proposal presented in the April 5, 2012 ACR for the utilities to rely on

[73] R.12-03-014 *Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans* dated March 22, 2012.

transmission cost estimates from CAISO Generator Interconnection Procedures (also referred to as GIP) studies (or equivalent), if available, rather than their TRCRs in their LCBF evaluations. We also adopt, in part, the proposal, to require projects to have completed a certain level of progress on interconnection studies before being placed on a utilities' shortlist to ensure that the project's total cost and value to ratepayers is considered in the shortlisting process.

The April 5, 2012 ACR presented two proposals that sought to capture a more accurate estimate of a project's transmission upgrade costs and the resulting value to ratepayers. One proposal was that, to the extent transmission cost estimate from the CAISO GIP studies (or equivalent) are available, the utilities rely on this data for their LCBF evaluations rather than the cost estimates from the TRCRs to more accurately reflect a bid's value to the ratepayer.[74] Another proposal was to require two shortlists. As proposed, the Primary Shortlist would consist of bids that have obtained CAISO GIP Phase II study results (or equivalent) or executed Interconnection Agreements. The Provisional Shortlist would consist of remaining shortlisted bids. Executed contracts would only be permitted from bids off the Primary Shortlist.[75]

Parties generally supported the use of CAISO Generator Interconnection Procedures studies cost estimates in LCBF evaluations as an additional option to the existing process. Some parties objected to being required to use CAISO GIP study results and recommended flexibility in estimating transmission upgrade costs, noting that CAISO GIP study results may not always be the most accurate

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[74] More information about the CAISO GIP is available at www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx.

[75] More details regarding this proposal can be found in the April 5, 2012 ACR.

estimate of transmission upgrade costs.[76] To achieve greater cost certainty, PG&E recommended requiring bids to have a completed CAISO GIP Phase I study before being eligible to participate in an RPS solicitation.[77] Both IEP and Tenaska supported PG&E's proposal of requiring bids to have completed the CAISO GIP Phase I study as this would allow utilities to have more refined estimates of transmission costs and enhance project viability in the RPS solicitation process. [78] Zephyr/Pathfinder, however, opposed PG&E's proposal arguing that the proposal places undue emphasis on CAISO GIP Phase I studies.[79] SCE made a different proposal, that a CAISO GIP Phase II study be completed prior to contract execution. [80] CalWEA and IEP opposed SCE's proposal on the basis that it would delay contract negotiations and executions.

Regarding the proposal to create two shortlists, most parties opposed the proposal on the basis that two shortlists were simply not necessary and could impede the negotiation process.[81]

As stated above, the goal of the proposals in the April 5, 2012 ACR was to have the most current and accurate cost information at key decision points in the

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[76] PG&E 2012 RPS Procurement Plan, May 23, 2012 at 70; SCE comments, May 23, 2012 at 5; CEERT comments, June 27, 2012 at 24; Zephyr/Pathfinder comments, June 27, 2012 at 4; Capital Power comments, June 27, 2012 at 4.

[77] PG&E updated 2012 RPS Procurement Plan, August 15, 2012 at 74.

[78] IEP comments, June 27, 2012 at 6; Tenaska comments, June 27, 2012 at 6.

[79] Zephyr/Pathfinder comments, June 27, 2012 at 4.

[80] SCE draft 2012 RPS Procurement Plan, May 23, 2012 at 27.

[81] CalWEA comments, June 27, 2012 at 5; Zephyr/Pathfinder comments, June 27, 2012 at 4; LSA reply comments, July 18, 2012 at 2; IEP reply comments, July 18, 2012 at 9; SCE comments, May 23, 2012 at 6.

RPS procurement process to minimize ratepayer costs and maximize value to the ratepayer. Currently, two of these key decision points are (1) the shortlisting of bids from solicitations and (2) final contract execution. If bids are required to have completed CAISO GIP Phase I studies at the time of bidding, as PG&E proposed, then the utility would have CAISO GIP Phase I study estimates available for all bids which could then be incorporated in the LCBF evaluations used to determine which bids are shortlisted. If, as SCE proposed, projects are required to have completed CAISO GIP Phase II studies prior to contract execution, which is a key decision point, then the availability of this more refined transmission cost estimate would ensure that more current and more accurate information is considered by the seller and utility prior to contract execution and, in addition, by the Commission when deciding whether or not to approve the contract.

The proposed decision suggested to combine PG&E's and SCE's two proposals to achieve the goal sought by the proposals in the April 5, 2012 ACR. In comments to the proposed decision, parties pointed out that the timeline required to obtain a CAISO GIP Phase II study is often unpredictable and likely to exceed the 12-month lifespan of the shortlist. As a result, a requirement to obtain a Phase II study prior to contract execution would be largely incompatible with the separate requirement for the shortlist to expire within 12-months. We agree that these two requirements are largely incompatible presently. Therefore, we do not adopt the recommendation in the proposed decision that projects have a minimum of a CAISO GIP Phase II study prior to contract execution but will continue to examine the merits of this requirement in a later part of this proceeding. We do, however, adopt PG&E's proposal for projects to obtain a CAISO GIP Phase I study prior to offering a bid into a solicitation. We evaluated

PG&E's proposal together with today's adopted change to the pro forma agreement which requires parties to agree upon a network upgrade cost cap (section 4.3.1 herein) and find that, together, these two new requirements meet the goal of the April 5, 2012 ACR to capture a more accurate estimate of a project's transmission upgrade costs and the resulting value to ratepayers. We make no changes to the current practices regarding the utilities' use of the TRCRs as adopted in D.05-07-040.[82] The Commission intends to review the need for TRCRs before the next procurement cycle.

Accordingly, in the final 2012 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E and SDG&E shall modify their RPS bid solicitation protocols, as needed, to require bids have the minimum of a completed CAISO GIP Phase I (or equivalent)[83] study to bid into the solicitation. This directive applies to future RPS Procurement Plans filed by PG&E and SDG&E unless otherwise directed by the Commission. While SCE will not hold a 2012 solicitation, SCE shall modify future bid solicitation protocols consistent with these requirements unless otherwise directed by the Commission.

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[82] D.05-07-040, *Interim Opinion Regarding Transmission Costs in RPS Procurement* (July 21, 2005).

[83] For projects that will be interconnecting on the distribution level: completed Fast Track or completed System Impact Study; for projects that will be interconnecting outside the CAISO's or the investor-owned utility's jurisdiction: equivalent interconnection progress.

4.4.2. Increase Minimum Project Size to Greater than Three Megawatts

This decision retains the existing limitations on the minimum size of projects eligible for participation in the RPS Program of 1.5 MW because presently a larger size limitation is not warranted.

PG&E's, SCE's, and SDG&E's draft 2012 RPS Procurement Plans each included a requirement setting the minimum nameplate capacity size of a project eligible to participate in an RPS solicitation. Previously, the Commission directed these utilities to set the minimum capacity for projects bidding into the RPS Program's solicitation at 1.5 MW based on then available contracting options for smaller projects under the Feed-in-Tariff program.[84] Recently, the Commission increased the maximum project size that may participate in the Feed-in Tariff program, consistent with statutory amendments.[85]

However, because we envision the RPS Program as a program with broad eligibility, we adopt no changes to the existing size limitation of 1.5 MW.

5. PG&E's 2012 RPS Procurement Plan

5.1. Ranking Bids Using a Portfolio-Adjusted Value Methodology

In this decision, we accept PG&E's request to include its Portfolio-Adjusted Value methodology in its solicitation protocol. We accept this Portfolio-Adjusted Value methodology for the 2012 solicitation. The Commission will review this matter further and determine whether this

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[84] D.08-02-008, *Opinion Conditionally Accepting Procurement Plans for 2008 RPS Solicitations* (February 2, 2008) at 31.

[85] D.12-05-035, *Decision Revising Feed-in Tariff Program, Implementing Amendments to Public Utilities Code Section 399.20 Enacted by Senate Bill s 380, Senate Bill 32 and Senate Bill 2 1X and Denying Petitions for Modification* at 62.

methodology is appropriate for use beyond the 2012 solicitation later in this proceeding when we review LCBF.

In PG&E's 2012 RPS Procurement Plan, PG&E proposed to adjust the net market values of bids to account for a bid's impact on PG&E's bundled electric portfolio. PG&E referred to this adjusted net market value as the Portfolio-Adjusted Value or PAV. The PAV adjustment methodology includes adjustments based on location, resource adequacy, portfolio need for RPS energy, uncertainty regarding project output, number of hours of buyer curtailment, term length, and transmission costs.

CalWEA recommended against PG&E's use of a PAV because many of the adjustments in PG&E's PAV methodology are already captured in the existing net market value calculation. CalWEA further commented that the adjustments are not described with sufficient clarity such that a bidder could understand how the bid would be affected. In response to this concern, PG&E's included a description of a refined version of its PAV in its comments to the proposed decision on October 29, 2012.

We accept the use of the Portfolio-Adjusted Value (revised per PG&E's October 29, 2012 comments) for PG&E's 2012 RPS solicitation. We find that PG&E's revised Portfolio-Adjusted Value methodology is sufficiently clear in setting forth the methodology for review of bids so as to permit bidders to know in advance the criteria used for bid evaluation by PG&E under the revised PAV. Prior to PG&E's submission of the revised PAV, we were concerned that the PAV lacked sufficient clarity to enable bidders to know in advance how bids will be evaluated, which, in turn, assists bidders to focus on the factors to be judged and promotes a fair, transparent and open process.[86]

In this decision, we only accept the use of the PG&E's Portfolio-Adjusted Value for the 2012 solicitation. We make no finding on the adequacy of the Portfolio-Adjusted Value for use beyond PG&E's 2012 solicitation. We only accept PG&E's PAV for the 2012 solicitation because we intend to review certain aspects of the PAV early next year in this proceeding. At that time, we intend to review how the PAV can be used to provide greater transparency to bidders and the merits of PG&E's use of the PAV when a similar evaluation methodology is not used by SCE and SDG&E.

Accordingly, in the final 2012 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E may include its Portfolio-Adjusted Value methodology in its 2012 solicitation protocol and must also include the LCBF and NMV methodologies, as referred to in a separate section of this decision.

5.2. Tax Credit Mitigation Option Term

In this decision, we agree with PG&E that the Production Tax Credit and the Investment Tax Credit term in the pro forma agreement should be removed as it is likely that these federal tax credits will expire before contracts resulting from the 2012 RPS solicitation are executed. We acknowledge, however, that pro forma agreements may be modified, as agreed to by the contracting parties, to include negotiated terms, including the proposed term related to the federal tax credits.

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[86] D.03-06-071 at 37; D.04-07-029 at 28, Findings of Fact 27 and 28; D.06-05-039 at 50-53, Conclusion of Law 3; and D.07-02-11 at 35.

In PG&E's 2011 RPS Procurement Plan, the Commission approved a term in its pro forma agreement, referred to as the Tax Credit Mitigation Option, which is related to the Production Tax Credit[87] and the Investment Tax Credit.[88] This term allowed PG&E and the seller to re-negotiate their contract under certain circumstances related to these tax provisions.[89] In its draft 2012 RPS Procurement Plan, PG&E proposed to remove the Tax Credit Mitigation Option term from its pro forma agreement. PG&E proposed this change based on the expectation that projects bidding into the next RPS solicitation will enter into contracts commencing after these tax credits expire.

The Division of Ratepayer Advocates (DRA) supported removal of this contract term because it would require projects to be financially more self-sufficient and less reliance on subsidies.[90] CalWEA, TURN, and IEP opposed removal of the term because it will have an adverse effect on project viability by increasing the risk of projects since developers will have to make an assumption regarding whether or not tax credits will be extended.[91] IEP also joined LSA in offering alternative solutions. IEP proposed that projects bidding into the solicitation with commercial operation dates scheduled to occur after the

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[87] The Production Tax Credit is a federal renewable electricity tax credit for a per kilowatt-hour tax credit for electricity produced by qualified energy resources, 26 U.S.C. § 45.

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

[89] PG&E 2011 RPS Form of Power Purchase Agreement, Section 11.1(c).

[90] DRA comments, June 27, 2012 at 14.

[91] CalWEA comments, June 27, 2012 at 16; TURN reply comments, July 18, 2012 at 4-6; IEP comments, June 27, 2012 at 7.

expiration of these federal tax credits be provided the option to submit two bids to solicitations -- one bid with a price that assumes the federal tax credits are not available and another bid price that reflects the availability of federal tax credits.[92] LSA proposed that the Commission address this issue by first acknowledging the scheduled expiration of the federal investment tax credit and then directing PG&E, SCE, and SDG&E to procure resources to meet their unmet RPS need in the third compliance period, years 2017-2020,[93] before the expiration of the Investment Tax Credit at the end of 2016.[94] TURN supports this effort to procure before 2016 for compliance period 2017-2020 in order to capture the potentially large value for ratepayers in the form of lower contract prices resulting from these tax credits.[95]

In evaluating this contract term, we first acknowledge that individual terms of the RPS pro forma agreement are negotiable, except for the "standard terms and conditions." With that consideration in mind, we then assess whether or not PG&E's proposal to remove the term from the pro forma agreement is reasonable. The federal Production Tax Credit is currently scheduled to expire

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[92] IEP comments, June 27, 2012 at 7; IEP reply comments, June 27, 2012 at 5 (reiterating support for creation of an option to offer two bids with different prices, one assuming no tax credits and one reflecting tax credits, for the same project.

[93] The third compliance period, years 2017-2020, is established in § 399.15(b)(1)(C) and implemented by the Commission in D.11-12-020, Decision Setting Procurement Quantity Requirements for Retail Sellers for the Renewables Portfolio Standard Program (December 1, 2012).

[94] LSA comments, June 27, 2012 at 3; LSA reply comments, July 18, 2012 at 12.

[95] TURN reply comments, July 18, 2012 at 6.

on December 31, 2012 for new wind projects[96] and the Investment Tax Credit, available for solar installations, is only available for new systems placed in service before December 31, 2016.[97] Given the timing of the expiration of these federal tax incentives, it seems probable that contracts resulting from PG&E's 2012 solicitation may have commercial operation dates commencing after the expiration of one or both of these federal tax credits.[98]

As stated by TURN, renewable developers will seek to benefit from any federal tax incentives available to them at the time they prepare their bids regardless of whether this term is included in the pro forma agreement.[99] We agree and find that because an individual developer may negotiate a Tax Credit Mitigation Option Term in a specific contract on a project-by-project basis, it is reasonable to remove of the Tax Credit Mitigation Option Term from the pro forma agreement but acknowledge that parties may decide to agree to include this term in their contract.

We decline to accept LSA's and TURN's proposal to encourage PG&E, SCE, and SDG&E to procure 2016 generation during or before the 2012 RPS solicitations to capture the benefits of the expiring federal tax credits and apply those transactions to compliance period 2017-2020 because we lack sufficient

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[96] 26 U.S.C. § 45 (Internal Revenue Code). Additional information can be found under Extension of Renewable Energy Production Tax Credit (Section 1101) at http://www.irs.gov/newsroom/article/0,,id=209564,00.html.

[97] See, http://selectusa.commerce.gov/investment-incentives/business-energy-tax-credit.

[98] We acknowledge that these tax credits have been extended in the past and could, therefore, be extended again.

[99] TURN reply comments at 5.

evidence to justify this departure from the existing compliance period obligations. Similarly, in response to IEP's recommendation to permit a duel bidding structure, the Commission finds that, at this point in the proceeding, insufficient evidence exists as to the reasonable outcomes to justify creating a dual bidding structure in which project bid into the RFO with two prices, one that includes the federal tax credits and another that does not.

Accordingly, in the final 2012 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E and SDG&E shall remove the Tax Credit Mitigation Option Term or similar term from their pro forma agreements. Parties are not prohibited from agreeing to include this term in their contracts on a case-by-case basis. This directive applies to future RPS Procurement Plans filed by PG&E and SDG&E unless otherwise directed by the Commission. While SCE will not hold a 2012 solicitation, SCE shall modify future bid solicitation protocols consistent with this requirement unless otherwise directed by the Commission.

5.3. Relaxed Letter of Credit Requirements

In this decision, we accept the proposal by PG&E to modify its pro forma agreement to relax the threshold for banks to qualify as eligible to issue letters of credit for RPS contracts, which is consistent with the existing provisions of SCE's and SDG&E's pro forma agreements. In addition, we accept the proposal by PG&E to amend RPS contracts executed through its annual RPS solicitations that have the prior credit rating requirements such that the amendment is equivalent to PG&E's new credit rating requirements.

In its draft 2012 Procurement Plan, PG&E proposed to relax the threshold for banks to qualify as eligible to issue letters of credit for RPS contracts.[100] PG&E proposed applying these relaxed standards to its 2012 RPS solicitation. PG&E's 2011 RPS Procurement Plan required banks to have either an "A" rating from Standard & Poor's Financial Services, LLC (a subsidiary of The McGraw Hill Companies, Inc.) or an "A2" rating from Moody's Investors Service, Inc.[101] PG&E now proposes relaxing those standards to allow banks with credit ratings of "A-" from Standard & Poor's Financial Services, LLC or "A3" from Moody's Investors Service, Inc., with an outlook designation of "stable" to participate in the RPS solicitations.[102] PG&E recommended this change in credit rating requirements because of "recent and ongoing turmoil in the financial markets and the uncertain credit rating of many banks" that developers often utilize pursuant to their RPS contracts.[103]

No parties filed comments on PG&E's proposal.

The Commission seeks to standardize contract terms and program provisions among procurement programs for the three large investor-owned utilities, when possible. The Commission also evaluates the reasonableness of individual proposed contract terms and conditions when considering an RPS contract. SCE and SDG&E currently apply the credit rating requirements that PG&E now proposes in its 2012 RPS Procurement Plans. For this reason, and

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[100] PG&E updated 2012 RPS Procurement Plan, August 15, 2012 at 89.

[101] PG&E 2011 RPS Procurement Plan, May 4, 2011 at PG&E Form of Power Purchase Agreement, Section 8.5 and at 60.

[102] PG&E updated 2012 RPS Plan, August 15, 2012 at 85.

[103] PG&E updated 2012 RPS Plan, August 15, 2012 at 89.

given the reasonableness of the proposed change in light of the global economic situation and PG&E's continued reliance on credit-worthy institutions to provide letters of credit under this proposal, the Commission finds PG&E's request to relax the credit rating requirements for financial institutions seeking to provide letters of credit for contracts resulting from the utility's RPS solicitations reasonable.

In addition to requesting approval of relaxed letter of credit requirements for its 2012 RPS contracts, PG&E requested Commission authority to amend executed RPS contracts with prior credit rating requirements and authority to amend non-modifiable contracts approved or pending approval from its Renewable Auction Mechanism and its Solar Photovoltaic Programs.[104] No parties filed comments on PG&E's proposal.

We approve PG&E's request for authority to amend executed contracts that are not based on non-modifiable form contracts because, as stated above, the modification is reasonable in light of the Commission's desire for standardization and current global economic situation. We deny, without prejudice, however, PG&E's request to apply this modified credit term or amend contracts from other programs outside of this RPS solicitation, such as the Renewable Auction Mechanism and Solar Photovoltaic program. It would be more appropriate for PG&E to raise this issue when the Commission addresses those specific programs.

Accordingly, in the final 2012 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E may modify its

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[104] PG&E updated 2012 RPS Procurement Plan, August 15, 2012 at 87.

pro forma agreement and any existing contracts in this RPS Program to relax the threshold for banks to qualify as eligible to issue letters of credit for RPS contracts to allow banks with credit ratings of "A-" from Standard & Poor's Financial Services, LLC or an "A3" rating from Moody's Investors Service, Inc., with an outlook designation of "stable" to participate in the RPS solicitations. This directive applies to future RPS Procurement Plans filed by PG&E unless otherwise directed by the Commission.

6. SCE's 2012 RPS Procurement Plan

As indicated above, SCE requested in its August 15, 2012 updated RPS Procurement Plan not to hold a 2012 RPS solicitation. We accept this proposal but reject SCE's request to execute bilateral contracts. We also address issues raised by SCE in materials filed with its RPS Procurement Plan to the extent relevant to the 2012 solicitation, even in SCE's absence, or to future solicitations.

6.1. SCE's Proposal Not to Hold a 2012 RPS Solicitation

In this decision we accept SCE's proposal to not hold a 2012 RPS solicitation. Each utility remains responsible for meeting its RPS Program procurement requirements. SCE reasonably explains that during the time period covered by the 2012 RPS Procurement Plans, it will address any unmet RPS compliance needs through smaller-scale renewable facilities that are less than 20 MW in size.[105] Moreover, should SCE determine it has an unmet RPS need during the 2012 solicitation cycle, we will revisit SCE's request to not hold a

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[105] SCE updated 2012 RPS Procurement Plan, August 15, 2012 at 1 and Appendix A at 5.

solicitation and the corresponding restriction adopted today (and discussed further below) on bilateral contracts.

In SCE's updated draft 2012 RPS Procurement Plan, SCE stated it no longer plans to hold an annual RPS solicitation for 2012.[106] In support of its proposal, SCE stated that "given the State's focus on procurement from smaller-scale renewable facilities, SCE will not hold an RPS solicitation in this solicitation cycle. Instead, SCE will focus on meeting its need through its procurement programs for smaller renewable resources."[107]

SCE also stated it forecasts a net long position for the first compliance period and the second compliance period.[108] SCE forecasts a net short position of approximately 11.7 billion kilowatt-hours (kWh) in the third compliance period without the use of banked excess procurement from the first two compliance periods. However, it is worth noting that SCE forecasts a net short position for 2021 and the years beyond under the Commission's renewable net short methodology.[109]

SCE stated that it will procure through a variety of programs for small-scale renewable resources. In procuring for small-scale renewables, SCE stated it expects to hold multiple solicitations – more than it has ever administered in one year - for other programs, such as the Feed-in Tariff program, the Renewable Auction Mechanism, Solar Photovoltaic Program

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[106] SCE updated 2012 RPS Procurement Plan, August 15, 2012 at 1 and Appendix A at 2.

[107] SCE updated 2012 RPS Procurement Plan, August 15, 2012 at 2.

[108] SCE updated 2012 RPS Procurement Plan, August 15, 2012 at 7.

[109] SCE updated 2012 RPS Procurement Plan, August 15, 2012 at Appendix A at 9. SCE states it may be able to fill this net short position through the use of banking.

(SPVP).[110] SCE stated that it will also be holding All-Source Requests for Offers open to RPS-eligible resources and Qualifying Facilities (QF) solicitations.[111] Lastly, SCE stated it is open to considering offers for bilateral contracts.[112]

IEP and LSA recommended that annual RPS solicitations be required for the three largest utilities.[113] IEP asserted that regular annual solicitations offer a consistent prospect of contracting opportunities to the market and that annual solicitations provide flexibility for IEP members to respond to changing conditions. LSA similarly stated it supports a predictable solicitation schedule.

In evaluating the reasonableness of SCE's proposal not to hold a general 2012 RPS solicitation, we consider the Commission's previous decisions and the reasonableness of SCE's overall 2012 RPS Procurement Plan, as updated, including information provided regarding its current forecast for meeting its RPS procurement quantity requirements over multiple compliance periods, consistent with the new compliance rules adopted in D.12-06-038. We also consider information provided by SCE and other parties in response to the ALJ ruling dated August 31, 2012.[114] In reviewing reasonableness of RPS Procurement Plans, the Commission generally reviews the plans at a high level while acknowledging that the utilities are accountable for meeting their RPS

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[110] SCE updated 2012 RPS Procurement Plan, August 15, 2012 at 2 and Appendix A at 5.

[111] SCE updated 2012 RPS Procurement Plan, August 15, 2012 at Appendix A at 5.

[112] SCE updated 2012 RPS Procurement Plan, August 15, 2012 at Appendix A at 10.

[113] IEP comments, June 27, 2012 at 22; LSA comments, July 18, 2012 at 9.

[114] August 31, 2012 *ALJ Ruling Requesting Additional Information from SCE Regarding Proposal not to hold a 2012 RPS Solicitation*. The ruling requested a response from SCE and responses from parties on an expedited schedule on the forecasted net long position and the impact on the expiration of the Investment Tax Credit.

requirements. Each utility is responsible for achieving successful procurement to meet the RPS Program requirements.

At the same time, the RPS plans are to include certain elements as required by statute and a level of detail such that the Commission may review a utility's solicitations and procurement for consistency with a utility's RPS Procurement Plan. As directed by the April 5, 2012 ACR, SCE included an assessment of its RPS procurement supplies and demands 2011 through 2022. We find it reasonable that SCE forecasts that it has a net long position in both compliance period 2011-2013 and compliance period 2014-2016 but a net short position of 14,700 GWh for the 2017-2020 compliance period.[115] We also find it reasonable for SCE to procure renewable resources through a number of programs that require procurement from facilities that under are 20 MW in size.

Within the context of SCE's request to not hold a solicitation in 2012, we do not find reasonable SCE's proposal that it will consider offers for bilateral contracts, and we do not accept this portion of SCE's 2012 RPS Procurement. SCE's request to enter into bilateral contracts for RPS products is inconsistent with SCE rationale for not holding a competitive solicitation. Furthermore, in D.09-06-050, the Commission adopted a contract review process for bilateral contracts.[116] Specifically, it was adopted that bilateral contracts should be reviewed according to the same standards as contracts that come through solicitations, including the evaluation of price reasonableness. The

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[115] SCE updated 2012 RPS Plan, August 15, 2012 at 7. This figure is based on SCE's methodology rather than the Commission's methodology.

[116] 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* at 28.

Commission's review of all RPS contracts includes a comparison of the contract to the most recent solicitation and recently executed contracts. As noted above, SCE is planning to procure through a number of small-scale renewable energy programs and will not hold an annual RPS solicitation. Without a solicitation, the Commission will not be able to adequately determine the reasonableness of bilateral contracts as no comparable market data for SCE will exist for the Commission to compare with the bilateral contract (assuming that the facility is greater than 20 MW in size).

The Commission has a preference for contracts from solicitations. If SCE has a need to procure, it should be done through a solicitation. This restriction on bilateral contracts will remain in effect until removed by a future decision (e.g., addressing RPS Procurement Plans) accepted by the Commission. We note, should SCE determine it has an unmet RPS need during the 2012 solicitation cycle, we will revisit SCE's request to not hold a solicitation and the corresponding restriction adopted today on bilateral contracts.

In comments on the proposed decision, IEP suggested, among other things, that if the Commission accepted SCE's proposal to forgo a 2012 RPS solicitation, the Commission should not permit SCE to propose any RPS utility-owned generation (UOG). Under § 399.14(a) and § 1001, a utility must submit an application to obtain Commission approval prior to initiating construction of any utility-owned renewable generation projects. As part of this process, SCE would have to present evidence of an unmet need for RPS generation. We find that, at this time, the statutory requirements establish a sufficient process for consideration of such matters and no further Commission action regarding RPS UOG is needed.

Accordingly, in the final 2012 RPS Procurement Plan to be filed with the Commission pursuant to the schedule adopted herein, SCE shall remove the consideration of bilateral offers.

6.2. Resource Adequacy: for a Period Less than the Term of the Contract and from Third Parties

While SCE will not hold a 2012 RPS solicitation, we address the following issue raised by SCE earlier in this proceeding to the extent it impacts PG&E and SDG&E and to the extent the issue has broader implications beyond the 2012 Procurement Plans. Today's decision considers and adopts SCE's request to permit the resource adequacy component of a contract, which is also referred to as the capacity-only component, to cover less than the entire term of the contract. Today's decision, however, does not allow contract bidders to acquire third-party resource adequacy for the purpose of bidding an "energy plus capacity" project into an RPS RFO. However, the Commission is receptive to reviewing this issue later in this proceeding.

While RPS contracts are typically for both energy and capacity, generators may choose to sell energy and capacity separately.[117] Accepting energy-only bids in RPS solicitations is consistent with D.11-04-030, which required the utilities to accept energy-only bids from sellers.[118] The Commission has applied the same rule in other RPS Programs, such as the Renewable Auction Mechanism[119] and

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[117] D.11-04-030, *Decision Conditionally Accepting 2011 Renewables Portfolio Standard Procurement Plans and Integrated Resource Supplements* at 20.

[118] D.11-04-030, *Decision Conditionally Accepting 2011 Renewables Portfolio Standard Procurement Plans and Integrated Resource Supplements* at 20.

[119] CPUC Resolution E-4489, *Adopting Modifications to the RAM Program Rules*, April 19, 2012 at 19-20.

the Renewable Feed-in-Tariff programs,[120] which also permit the sale of energy and capacity separately.

In SCE's draft 2012 RPS Procurement Plan dated May 23, 2012 (filed prior to SCE's proposal not to hold a 2012 solicitation), SCE sought permission from the Commission for bidders to have more flexibility in bidding the resource adequacy component of the transaction. SCE proposed that bidders be permitted to designate the years it will provide resource adequacy during the term of the contract, including a period of time that covers the entire term of the contract or subset thereof. SCE also proposed allowing bidders to offer third-party capacity to convey the resource adequacy component of the contract. Bidders would offer that capacity – limited by the Net Qualifying Capacity (NQC) of the bidders' own energy bid – combined with its energy offer into the utility's RFO as an "energy plus capacity" transaction.[121]

CalWEA, Solar Reserve, and the City and County of San Francisco supported SCE's request and recommended that the Commission require each of the utilities to allow for transactions related to third-party resource adequacy.[122] PG&E opposed SCE's proposal on the basis that short-term "substitute" capacity products do not provide the same value as long-term capacity agreements with specific facilities.[123]

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[120] D.12-05-035, *Decision Revising Feed-in Tariff Program, Implementing Amendments to Public Utilities Code Section 399.20 Enacted by Senate Bill s 380, Senate Bill 32 and Senate Bill 2 1X and Denying Petitions for Modification* (May 24, 2012) at 54-56.

[121] SCE 2012 RPS Procurement Plan, May 23, 2012 at 28.

[122] CalWEA comments, June 27, 2012 at 20; Solar Reserve comments, June 27, 2012 at 3; and County of San Francisco, reply comments, July 18, 2012 at 3.

[123] PG&E reply comments, July 18, 2012 at 11.

The Commission finds that SCE's proposal to allow for more flexibility with regard to the years that resource adequacy will be provided is reasonable given that full capacity deliverability status may not coincide with the contract term. In this event, we note that different TOD Factors may be appropriate for different segments of the contract based on the separate authorization in today's decision for two TOD Factors. The Commission declines to adopt SCE's proposal for sellers to bundle offers with third-party resource adequacy as the record is currently insufficient to assess the risks and benefits to ratepayers and to the RA market of permitting a seller to provide substitute resource adequacy through short-term arrangements compared to contractual agreements that provide long-term resource adequacy. However, the Commission is receptive to parties raising this issue in this proceeding at a later date when, for example, the Commission reviews LCBF later in this proceeding as set forth in the October 5, 2012 ACR and September 12, 2012 Amended Scoping Memo.

Accordingly, in the final 2012 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E and SDG&E may include a provision permitting the resource adequacy component of a contract, which is also referred to as the capacity-only component, to cover less than the entire term of the contract. This directive applies to future RPS Procurement Plans filed by PG&E and SDG&E unless otherwise directed by the Commission. While SCE will not hold a 2012 solicitation, SCE may modify future RPS Procurement Plans consistent with this requirement unless otherwise directed by the Commission.

6.3. Request for Authority to Sell Excess RPS-Eligible Generation by Tier 2 Advice Letter

This decision accepts SCE's proposal to hold a competitive solicitation for the sale of excess RPS products from existing facilities but does not accept SCE's proposal to rely on the Tier 2 Advice Letter process, instead of the now applicable Tier 3 Advice Letter process, for the purpose of obtaining approval for the sale of excess bundled renewable energy and unbundled renewable energy credits (RECs). We also permit the sale of excess RPS products through bilateral contracts and maintain the Tier 3 Advice Letter process for the purpose of obtaining Commission approval for those bilateral contracts as well.

In its draft 2012 RPS Procurement Plan, SCE sought authority to hold a competitive solicitation seeking proposals from interested buyers to purchase RPS-eligible energy and RECs as a bundled product, unbundled RECs, or other RPS-eligible products from SCE and requests that the Commission utilize the Tier 2 Advice Letter review process to accelerate the regulatory approval process of these sales transactions if the product being sold is associated with an existing facility.[124] Currently, a utility must use the Tier 3 Advice Letter process when seeking Commission approval of a contract that concerns the sale of RPS products, which requires disposition before a vote of the full Commission. Tier 2 Advice Letters may become effective after Energy Division Staff review.

DRA supported SCE's request to streamline regulatory approval of energy and associated RECs by utilizing the Tier 2 Advice Letter process, where final disposition may occur more quickly at the staff level.[125] DRA stated this change

[124] SCE 2012 RPS Procurement Plan, August 15, 2012 at 26.

[125] DRA comments, June 27, 2012 at 7.

would give the utilities more flexibility to rapidly respond to changing market conditions and agrees that there are fewer issues that require Commission review when considering the approval of sales of energy from existing facilities.[126] DRA did not provide specific examples in support of this statement.

In comments to the proposed decision, parties suggested that the sale of excess RPS products also be permitted through bilateral contracts. We find this suggestion is consistent with our decision to permit the sale of excess RPS products through the solicitation process.

The Commission seeks to promote the efficient management of a utility's RPS portfolio while maintaining necessary ratepayer protections. An expedited approval process for purchase and sales contracts was proposed in the October 5, 2012 Assigned Commissioner's Ruling. Moreover, based on the existing record in this proceeding, it is unclear whether the proposed change in the regulatory approval process will increase the utility's efficient management of its portfolio while maintaining sufficient ratepayer protections. Given the lack of a sufficient record to address the merits of SCE's proposal at this time, the Commission declines SCE's proposal for an expedited regulatory review process for excess REC and energy sales from existing facilities through the Tier 2 Advice Letter process but will consider it later in this proceeding. Approval of bilateral contracts for the sale of excess RPS products must also be obtained through a Tier 3 Advice Letter.

Accordingly, in the final 2012 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, PG&E, SCE, and SDG&E

[126] DRA comments, June 27, 2012 at 7.

may include a competitive solicitation and bilateral contracts to sell excess RPS products but shall not include a provision providing for the Tier 2 Advice Letter process, instead of the now applicable Tier 3 Advice Letter process, for the purpose of obtaining approval for the sale of excess bundled renewable energy and unbundled REC. This directive applies to future RPS Procurement Plans filed by PG&E, SCE, and SDG&E unless otherwise directed by the Commission.

7. SDG&E's 2012 RPS Procurement Plan - Portfolio Content Category as a Condition Precedent

In this decision, we do not accept SDG&E's proposal to modify its pro forma agreement to include a requirement that the Commission determine the portfolio content category of the resource prior to the contract becoming effective. Our decision is consistent with D.11-12-052, the Commission's recent decision implementing the statutory amendments in Senate Bill 2 1X pertaining to portfolio content categories and set forth in § 399.16(b)(1).

In its draft 2012 RPS Procurement Plan, SDG&E proposed to modify its pro forma agreement to include a term that would require the Commission to not only approve the contract but to also provide an upfront determination on the portfolio content category designation of the resource subject to the contract.[127]

We decline to authorize SDG&E to make this modification to its pro forma agreement because the proposed term is not consistent with RPS Program rules regarding portfolio content categories set forth in D.11-12-052, which defined and implemented the statutory provisions setting forth the portfolio content

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[127] SDG&E draft 2012 RPS Plan, May 23, 2012, Pro Forma Agreement, Section X at Y.

categories for the RPS Program, and the RPS Program's compliance rules.[128] In D.12-11-052, the Commission found that it would not determine the portfolio content category of RPS resources until the utility submits an RPS compliance report and supporting information, if necessary, for the Commission to determine the proper portfolio content categorization of the actual procurement and make a compliance determination.[129] The Commission has yet to establish a process for determining this aspect of RPS compliance. The Commission's evaluation of the reasonableness of RPS contracts and the approval of contracts are separate from the Commission's review of the utilities' RPS compliance with portfolio content category requirements. Therefore, a portfolio content category classification determination at the time of Commission approval of a contract is not appropriate.

Accordingly, in the final 2012 RPS Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, SDG&E shall not include a requirement that the Commission determine or approve the portfolio content category classification as a precondition to the contract's effectiveness. This directive applies to future RPS Procurement Plans filed by PG&E, SCE and SDG&E unless otherwise directed by the Commission.

8. Additional Issues Denied or Deferred

8.1. Two-Year Procurement Plan Cycle

In this decision we decline to adopt the proposal presented in the April 5, 2012 ACR to rely on a two-year procurement plan cycle.

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128 D.11-12-052, *Decision Implementing Portfolio Content Categories for the Renewables Portfolio Standard Program* at 17-43.

129 D.11-12-052 at 11.

In the April 5, 2012 ACR, parties were asked to comment on a proposal to authorize utilities to procure RPS-eligible resources over a two year planning horizon.[130] The proposal would apply to all retail sellers. Under the ACR's proposal, utilities would be required to file a full procurement plan once every two years and to file a Tier 3 advice letter in the off-years justifying why or why not they intended to conduct a solicitation, providing support for the decision including updated portfolio assessment, and updated solicitation material, if appropriate. Under the proposals, utilities would be required to hold solicitations simultaneously. The intent of this proposal was to streamline the procurement process without sacrificing the transparency provided by the filing of annual procurement plans.

Parties generally supported this proposal to the extent the Commission sought to streamline RPS procurement. SCE suggested that to further streamline the program, a comprehensive filing every three years might present additional benefits.[131] SCE also suggested consolidating several reports, such as the compliance report and the Project Development Status Report (PDSR), with the proposed advice letter filing. Regarding the annual filing requirement for RPS Procurement Plans noted in the statute, parties suggested that this requirement could be satisfied through one of the other RPS filings, such as the RPS compliance report or the Project Development Status Report.[132] Parties also questioned whether a need exists for an annual solicitation.

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[130] April 5, 2012 ACR at 22.

[131] SCE comments May 23, 2012 at 9.

[132] *See, e.g.*, SCE comments May 23, 2012 at 9.

Parties also raised several concerns regarding the two-year proposal. PG&E suggested to eliminate the proposal's recommendation that the utilities' annual RPS solicitation should occur at the same time. PG&E stated that the utilities should retain discretion over when to hold a solicitation. PG&E and SCE also expressed concern that the proposed Tier 3 advice letter process could turn into a full RPS Procurement Plan unless the scope and the schedule of the advice letter filing are more narrowly defined. SCE suggested that this Tier 3 advice letter be limited to material changes and updates, if any, to the annual plan.[133] SDG&E noted that one potential downside of holding less frequent solicitations, as set forth in the proposal, would be that solicitation data could become outdated and would then be a poor benchmark to use when evaluating bilaterally-negotiated contracts that are signed in the interim periods, between solicitations.[134]

We decline to adopt this proposal. However, we continue to be interested in ways to streamline the RPS procurement process while maintaining the flexibility and transparency of the program. The proposal holds promise in terms of reducing the administrative burden resulting from annual filings but leaves a number of details undeveloped in the absence of annual plans. For example, the scope and schedule of the Tier 3 advice letter, the level of discretion provided to utilities on whether to hold annual solicitations, and possible means of responding to unexpectedly high project failures, spikes in retail sales, or transmission failures, thus increasing the utilities' demand for RPS resources.

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133 SCE comments May 23, 2012 at 9.

134 SDG&E draft Procurement Plan, May 23, 2012 at 34-35.

These matters will be further developed as set forth in the October 5, 2012 ACR and the September 12, 2012 Amended Scoping Memo.

8.2. Modifications to Project Viability Calculator

In this decision we do not adopt the parties' proposals regarding project viability. The Commission previously addressed project viability in D.09-06-018.

In D.09-06-018, the Commission required that each utility include a project viability methodology and calculator in its amended 2009 Procurement Plan and solicitation protocols. In the same decision, the Commission directed the use of the Energy Division's Project Viability Calculator (as referred to as PVC) as part of a standardized project viability evaluation methodology within the RPS procurement process. Specifically, the Project Viability Calculator uses standardized categories and criteria to quantify a project's strengths and weaknesses in key areas of renewable project development. The PVC is a tool for standardized comparison of the viability of projects bid into RPS solicitations and not an indicator if a project will ultimately be successfully developed.[135]

In comments on the draft 2012 RPS Plans, several parties suggest modification to the role of project viability in the solicitation process. IEP recommended that the Commission direct the utilities to give greater weight, relative to price, to project viability.[136] The LSA further recommended that the Commission host a workshop and provide an opportunity for comments on how viability metrics should be modified to assess projects with more distant

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[135] D.09-06-018, *Decision Conditionally Accepting Procurement Plans for 2009 Renewables Portfolio Standard Solicitations and Integrated Resource Plan Supplements* at 21 and Conclusion of Law 9.

[136] IEP comments, June 27, 2012 at 3.

commercial online dates because current project viability metrics are not well-suited to assessing the viability of projects with more distant online dates.[137]

In deciding this issue, the Commission refers to our previous treatment of project viability and the project viability calculator in the RPS solicitation process. As stated above, in D.09-06-018, the Commission directed the use of the PVC. In directing the use of the PVC, however, the Commission noted that the PVC is an indicative rather than predictive tool and that the utilities remain responsible for the recommendations they make regarding projects necessary to meet their RPS Program requirements. We additionally stated that a project's PVC score is meant to be used as a screening tool, not to determine the exact merit of a particular project or contract.

While the Commission notes parties' comments relative to project viability, we decline in this decision to pursue modification of how viability and the PVC are currently applied by the utilities within their LCBF methodologies. The Commission reiterates its prior direction that the utilities use the PVC as one criterion in a utility's bid evaluation methodology and that the PVC is not intended to determine the exact merit of a particular project or contract but provides a relative comparison.

The Commission does find, however, that it would be worthwhile for Energy Division to work with interested parties to re-examine the PVC and if a revised PVC is developed, the utilities shall incorporate it into their evaluations of their 2012 RPS solicitations. Further, the role of project viability in the bid evaluation process may be further addressed when the Commission considers

[137] LSA comments, June 27, 2012 at 6.

reform of LCBF as set forth in the October 5, 2012 ACR and September 12, 2012 Amended Scoping Memo.

8.3. Process for Commission Review of Contract Amendments

In this decision, we decline to adopt certain proposals by IEP and SDG&E regarding contract amendments. Some of these proposals may be appropriate for Commission consideration later in this proceeding.

IEP made several proposals regarding contract amendments. Specifically, IEP recommended that the Commission identify which types of contract amendments are material and suggested that the Commission's review be limited just to those material amendments. IEP suggested this may permit contracts to be terminated and the previously contracted for MWs available for new contracts.[138] Additionally, SDG&E made specific suggestions in response to IEP's list of circumstances triggering a Tier 3 Advice Letter filing, including changes in generation technology, extension of Commercial Operation Date or COD by over 12 months, changes in delivery point requiring a new Phase I interconnection study, increases in capacity, changes affecting price such as modification to expected hourly delivery profile, project modifications that could change the portfolio content category classification.[139]

In deciding this issue, we note that the October 5, 2012 ACR included several new proposals related to the Commission's review of renewable generation procurement as part of an effort to streamline the RPS procurement process, including standards of review for contract amendments

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[138] SDG&E reply comments, July 18, 2012 at 12.

[139] SDG&E reply comments, July 18, 2012 at 12.

While the Commission notes parties' respective comments on contract amendments, it declines to prescribe in this decision any review standards regarding contract amendments because the Commission currently intends to address these issues later in R.11-05-005, as noted in the October 5, 2012 ACR and the September 12, 2012 Amended Scoping Memo.

8.4. RPS Confidentiality

This decision does not adopt the proposals made by parties regarding confidentiality. We intend, however, to address this matter later in this proceeding.

The Commission's policies regarding the treatment of confidential information are set forth in D.06-06-066, as modified by D.07-05-032 and D.08-04-023.[140] These decisions adopt a matrix process establishing a procedure in accordance with Section 454.5(g) for determining whether information is entitled to confidential treatment because it is market sensitive.[141]

CalEnergy proposed that the treatment of confidential information be modified. Specifically, CalEnergy recommended changes to the confidential treatment of RPS procurement data, such as bid prices, valuations and

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[140] D.06-06-006, *Interim Opinion Implementing Senate Bill No. 1488, Relating to Confidentiality of Electric Procurement Data Submitted to the Commission;* D.07-05-032, *Order Modifying Decision (D.) 06-06-066 and Denying Rehearing of the Decision, as Modified;* D.08-04-023, *Decision Adopting Model Protective Order and Non-Disclosure Agreement, Resolving Petition for Modification and Ratifying Administrative Law Judge Ruling.*

[141] D.06-06-006, *Interim Opinion Implementing Senate Bill No. 1488, Relating to Confidentiality of Electric Procurement Data Submitted to the Commission, as modified by D.07-05-032, Order Modifying Decision (D.) 06-06-066 and Denying Rehearing of the Decision, as Modified* at 41 and 42, market sensitive information is defined as having the potential to materially affect an electricity buyer's market price for electricity, or the price an electricity buyer pays for electricity.

disclosures of aggregate bid data but individual prices remain confidential, as addressed in D.06-06-006, as modified by D.07-05-032.[142] SDG&E and SCE opposed CalEnergy's proposals. SDG&E stated that CalEnergy's proposal would require market participants to disclose confidential market-sensitive and trade secret procurement information.[143] SCE argued that such information is protected by statute and well-established Commission precedent.[144]

In deciding this issue, as noted above, we refer to the rules regarding treatment of confidential information set forth in D.06-06-006, as modified by D.07-05-032 and D.08-04-023. The Commission's rules presume that information should be publicly disclosed and that the burden is on the entity claiming confidentiality to prove why those disclosures should not be public. While parties generally did not oppose increased transparency, they disagreed on what information should be disclosed to the public. Therefore, while the Commission notes the parties' comments regarding specific and general confidentiality issues and acknowledges that many of the parties' comments may result in constructive changes to our current rules, more analysis is required to address confidentiality issues holistically, especially with regards to changes appropriate for the RPS Program framework under Senate Bill 2 1X. Therefore, we decline to address these confidentiality issues at this time.

We do expect, however, to address confidentiality issues later in this proceeding as related to the RPS Program. Specifically, the Amended Scoping Memo states the intent to review and possibly refine the Commission's rules on

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[142] CalEnergy comments, June 26, 2012 at 16.

[143] SDG&E reply comments, July 18, 2012 at 2.

[144] SCE reply comments, July 18, 2012 at 23.

confidentiality of procurement-related documents and information as applied to the RPS context. Confidentiality may also be addressed in the other forums identified there. As such, we envision an opportunity for parties to pursue an efficient balance between visibility and protection of procurement data that will allow the Commission to make constructive changes, if necessary, to the treatment of confidential RPS information and increase RPS Program transparency without distorting market investment signals at a future date in this proceeding.

8.5. Additional Independent Evaluator Report

In this decision, we do not adopt the proposal presented in the April 5, 2012 ACR to establish an additional Independent Evaluator report at an earlier point in the RPS procurement process as evidence does not exist at this time that such a report will improve our review of the RPS procurement process.

The April 5, 2012 ACR included a proposal to, in essence, split the existing Independent Evaluator report into two reports so that the Commission could review the RPS procurement earlier in the process.[145] Specifically, the April 5, 2012 ACR proposed that the first portion of the preliminary Independent Evaluator report on the topics of bid solicitation protocols and LCBF

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[145] In D.06-05-039, *Opinion Conditionally Approving Procurement Plans for 2006 RPS Solicitations, Addressing Time of Delivery Benchmarking Methodology, and Closing Proceeding* May 25, 2006, the Commission required that PG&E, SCE, and SDG&E use an Independent Evaluator to evaluate and report on the entire procurement process. The Commission did not adopt specific review and reporting guidelines for Independent Evaluators. Since that time, the RPS Program has undergone several changes with the implementation of Senate Bill 2 1X. Recent changes and upcoming revisions may influence the role of Independent Evaluator reporting both in terms of approach and content.

methodologies be submitted with the utilities' draft RPS procurement plan and the remaining portions on the topics of bid solicitation review, evaluation and selection process, be submitted with the utilities' shortlists. The current practice is for the utility to submit the Preliminary Independent Evaluator report after bids are shortlisted as part of the utility's solicitation shortlist report.

Some parties opposed this proposal while others supported it. SCE, SDG&E, Capital Power, IEP and CEERT opposed the proposal as being unnecessary and duplicating work, as well as creating a time delay in the already short schedule for submitting RPS Procurement Plans. SCE proposed that if adopted, the additional report should be applicable to the next procurement cycle in 2013. IEP further stated that Independent Evaluator reports are not critical enough for the proposal to be meaningful and recommended that the Commission ensure that any preliminary Independent Evaluator reports not be excessively redacted and shrouded in confidentiality.

PG&E supported the proposal starting with the next procurement cycle in 2013 and recommended that the additional Independent Evaluator report be limited to a review of the LCBF criteria used evaluating bids and not include a review of procurement targets and objectives. CalWEA, DRA, and Ormat generally support the proposal and encourage public disclosure of LCBF inputs and calculations.

In deciding this issue, as noted above, the Commission will be addressing related issues in its review of LCBF and related matters at a later date in this proceeding.

Accordingly, while the Commission notes parties' comments on the proposal presented in the April 5, 2012 ACR for an additional earlier Independent Evaluator report, we decline to prescribe in this decision such a modification to current practice. Based upon the upcoming review of the other aspects of the RPS Program, the Commission proposes to potentially address this issue within the larger context of RPS procurement.

8.6. Effort to Minimize Overall Transmission Cost

In this decision, we decline to address at this time the proposal presented in the April 5, 2012 ACR regarding minimizing overall transmission upgrade costs. Transmission costs are recognized as potential impediments to achieving RPS Program goals. We intend to continue the consideration of this matter as this proceeding continues.

The April 5, 2012 ACR includes a proposal to utilize the RPS procurement process to minimize transmission costs. Specifically, it was proposed to limit the amount of new generation procured in certain areas to ensure that costly network upgrades would not be triggered. Comments regarding the minimization of transmission costs to avoid triggering costly network upgrades were received from twelve parties opposing the proposal and four parties supporting the proposal. All parties recommend significant modifications to the proposal. Parties also recommend a review of the CAISO deliverability requirements.

CalWEA, CEERT, Zephyr/Pathfinder, Tenaska, Capital Power, LSA, and TransWest opposed the proposal on the grounds that it is overly complex, too qualitative, and too narrowly defined. IEP and Capital Power opposed the proposal on grounds that it is unnecessary, particularly in light of the fact that utilities are unlikely to sign contracts with projects that have not obtained full deliverability status from CAISO.

Zephyr/Pathfinder opposed the proposal and concurred that the Commission focus on minimizing the total cost of delivered power rather than just transmission costs.

IID opposed the proposal but recommends that the Commission clarify how to determine which non-CAISO projects do not trigger unnecessary network upgrades. Solar Reserve opposed the proposal on the grounds that the April 5, 2012 ACR and 2012 RPS Procurement Plans fail to recognize that costs are being driven up by CAISO rules on allocation of import capability. The City and County of San Francisco opposed the proposal in its current form and recommended that Commission hold a workshop in order to ensure that utilities procure resource adequacy as cost-effectively as possible and to also encourage the CAISO to revise its methodology and assumptions in interconnection studies.

PG&E, SCE, SDG&E, and the Sierra Club generally supported the proposal. However, these parties characterized the ACR's proposal as too vague in terms of methodology and impact on the solicitation schedule.

The purpose of the proposal in the April 5, 2012 ACR was to address transmission upgrade costs as related to renewable procurement. This issue is also being considered by the CAISO and, while we decline to address it today, we will continue to work with the CAISO and will consider this issue in a subsequent part of this proceeding as set forth in the October 5, 2012 ACR.

8.7. Energy Storage Proposal

In this decision, we decline to adopt the proposals made by the California Energy Storage Alliance (CESA) regarding energy storage. Energy storage systems may be a viable and cost effective solution to meeting California's clean energy goals. However, the Commission is exploring this issue in a separate proceeding. On December 16, 2010, the Commission opened R.10-12-007 pursuant to Assembly Bill 2514 (Skinner, Stats. 2010, ch. 469). These issues may also be addressed later in this proceeding as described in the September 12, 2012 Amended Scoping Memo and October 5, 2012 ACR.

In R.10-12-007, the Commission adopted D.12-08-016 which established an energy storage framework outlining the Commission's approach to energy storage system, including a roadmap for developing policy and addressing the economic and regulatory barriers to energy storage system deployment. R.10-12-007 remains open and a second phase of the proceeding is scoped to analyze the priority scenarios contained in the adopted framework.

CESA proposed that the Commission include in this proceeding a number of issues related to energy storage.[146] These issues included (1) the costs and benefits of employing energy storage systems for integration of RPS-eligible projects in RPS procurement; (2) including energy storage system technologies as a design option in RPS-eligible projects in RPS procurement plans, RFOs, and bid evaluation factors; and (3) clarifying the definition of ancillary services as included in RPS bid evaluation. CESA also suggested that the Commission schedule a workshop to consider the implications of energy storage systems and integrating renewables.

Given the complexity of the issues related to energy storage systems and the fact that the Commission has framed this matter in a separate proceeding, R.10-12-007, we decline to adopt any of CESA's proposals.

Additional opportunities to address energy storage may arise in the context of the review of LCBF methodology which we intend to address later in

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[146] CESA reply comments, July 18, 2012 at 2.

this proceeding as set forth in the October 5, 2012 ACR and September 12, 2012 Amended Scoping Memo.

9. Adopted Schedule for 2012 RPS Bid Solicitations

The utilities all propose similar schedules for the 2012 RPS bid solicitations. The proposals include a date before which a utility may not request an exclusivity agreement from a bidder before continuing negotiations.

The Commission adopts a schedule that reflects its experience with the 2011 solicitation, as set forth in D.11-04-030, and prior solicitations. The adopted schedule provides utilities and Energy Division Staff reasonable flexibility for contracts resulting from the solicitation. The same approach for Commission review and acceptance, rejection or modification of the final 2012 RPS Procurement Plans will be used as was employed for prior plans.

As in 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 2012 RPS solicitation process. Parties may seek schedule modification by letter to the Executive Director consistent with Rule 16.6 of the Commission's Rules of Practice and Procedure.

SCHEDULE FOR 2012 SOLICITATION

LINE NO.	ITEM	NO. OF DAYS (cumulative)
1	Mailing of Commission decision conditionally accepting 2012 RPS Procurement Plans	0
2	PG&E, SCE and SDG&E file final 2012 RPS Procurement Plans	15
3	PG&E and SDG&E issue RFOs (unless amended Plans are suspended by Energy Division Director by Day 25)*	25

LINE NO.	ITEM	NO. OF DAYS (cumulative)
4	PG&E and SDG&E notify Commission that bidding is closed	84
5	PG&E and SDG&E notify bidders of shortlist; no exclusivity agreements may be required before this date	144
6	PG&E and SDG&E submit shortlists to Commission and Procurement Review Group	154
7	PG&E and SDG&E file by Tier 2 advice letter (a) Evaluation Criteria and Selection Process Report and (b) Independent Evaluator's Report	184
8	PG&E and SDG&E 2012 RPS Solicitation Shortlists Expire	519
9	PG&E and SDG&E submit Advice Letters with contracts/PPAs for Commission approval	TBD

*The utility may adjust this date to a day after day 25, as necessary, without Commission approval.

10. Organization of 2013 RPS Procurement Plans and Supplements

For the next RPS procurement cycle, the Commission adopts the same approach used with the 2006, 2007, 2008, 2009, 2011, and 2012 Plans.[147] The filing and service of 2013 draft RPS Procurement Plans and draft solicitation protocols by utilities is expected to occur during the first half of 2013. The same applies to 2013 review of the ESPs' procurement plans.[148] The final schedule will be

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[147] 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.

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

announced in a ruling. The multi-jurisdictional utility, PacifiCorp, may file Supplements or Integrated Resource Plans consistent with this decision, D.08-05-029, and D.11-040-030.

11. Motion for Reconsideration by Shell Energy North America (US), L.P. and the Direct Access Customer Coalition – Denied

We deny the motion filed on April 17, 2012 by Shell Energy North America (US), L.P. and the Direct Access Customer Coalition for reconsideration of Assigned Commissioner's April 5, 2012 ruling. The motion requested reconsideration of the requirement in the April 5, 2012 ACR that ESPs file RPS procurement plans. Several parties opposed the motion.[149]

ESPs are required to file RPS procurement plans pursuant to § 365.1 and D.11-01-026. In D.11-01-026, the Commission found that most significant RPS requirements currently apply equally to large investor-owned utilities and ESPs. The filing of an RPS Procurement Plan is a significant RPS requirement and supported by statute.[150] We also find that the plans provide critical information to the public about the progress a retail seller is making toward the goals of the RPS Program. Therefore, in the absence of any substantial justification, we conclude the requirement to file plans equally applies to ESPs.

The motion is denied.

12. Comments on Proposed Decision

The proposed decision ALJ DeAngelis in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments

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[149] *Joint Response of SCE and PG&E to the Motion of Shell et al.* filed on May 2, 2012.

[150] § 399.11 *et seq.*

were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on October 29, 2012 and reply comments were filed on November 5, 2012. These comments have been reviewed. Changes to the proposed decision were made in response to the comments, as indicated.

13. Assignment of Proceeding

Mark J. Ferron is the assigned Commissioner and Regina M. DeAngelis is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. SDG&E has approximately 3,300 GWh under contract from projects that will be facilitated by the Sunrise Powerlink Transmission Project.
2. SDG&E continues to consider contracting with projects located in the Imperial Valley region.
3. The Independent Evaluator's report captures the robustness of the responses to PG&E's 2009 and 2011 RPS solicitations in the Imperial Valley region.
4. There has been a lack of interest in special Imperial Valley Bidder's conferences in the past and the event has created confusion.
5. If the utilities each assume a MIC of 1,400 MW for projects in the Imperial Valley area, when in reality, that MIC must be shared among all requesting load-serving entities, utilities are likely to over-value imports from IID.
6. Requiring the utilities to each use a 1,400 MW MIC value for projects in the IID area may result in equity concerns regarding bids at other interties.
7. The solicitation preferences set forth in the utilities 2012 RPS Procurement Plans are consistent with the RPS Program's policies and rules.
8. The goal of the proposal in the April 5, 2012 ACR to standardize the variables considered in the NMV calculation was to increase transparency in the

LCBF evaluation process and streamline review of bid solicitations and contracts by establishing a standardized set of values and costs. Standardization will better promote comparison between the utilities.

9. The addition of new variables to the NMV calculation could potentially add to the robustness of the calculation but sufficient evidence does not presently exist for determining whether these additional variables would be more appropriately included as part of the NMV calculation or as a separate aspect of the utilities' LCBF evaluations.

10. Deferring the adoption of a non-zero integration cost is reasonable until developed in a public forum.

11. The pro forma agreements are negotiable, except for the "standard terms and conditions" and serve as the starting point for negotiating a final agreement between the seller and utility.

12. The contract term regarding a transmission upgrade cost cap and the related buy-down provision serves to limit the total RPS procurement costs to ratepayers by linking contract termination rights to limits on transmission network upgrade costs.

13. The April 5, 2012 ACR presented a proposal that bids shortlisted by the utilities would have to be executed, if at all, within 12 months from the date that the utility submits its final shortlist to the Commission. The benefits of being able to compare a contract's value and price to current solicitation data outweighs the concerns regarding adopting a limited contract negotiation period.

14. The proposal presented in the April 5, 2012 ACR for the shortlist to expire after 12 months ensures consistency by prohibiting the utility to then execute a bilateral contract for the same project until a subsequent solicitation is initiated. The project is permitted to bid into any subsequent RPS solicitation.

15. Consistent with D.11-04-030, PG&E and SDG&E must accommodate bids that are energy-only or fully deliverable in their 2012 solicitation protocols.

16. The proposals in the April 5, 2012 ACR to create two shortlists sought to provide the most current and accurate cost information at key decision points in the RPS procurement process so as to minimize ratepayer costs and maximize value to the ratepayer.

17. In the past, the Commission has directed utilities to set the minimum capacity for projects bidding into the RPS Program's solicitation based on the availability of options for contracting through other programs, such as the Feed-in-Tariff program, that target smaller generation.

18. PG&E's Portfolio-Adjusted Value methodology, as revised in comments filed on October 29, 2012 and November 5, 2012 sufficiently describes the criteria used to evaluated bids to provide bidders with transparency on the bid evaluation process.

19. Projects bidding into the 2012 RPS solicitation will most likely propose contracts commencing after the Production Tax Credit and the Investment Tax Credit expire.

20. The Commission seeks to standardize contract terms and program provisions among procurement programs for the three large investor-owned utilities when possible.

21. SCE and SDG&E currently apply the credit rating requirements that PG&E now proposes in its 2012 RPS Procurement Plan.

22. During the time period covered by the 2012 RPS Procurement Plans, SCE can address any unmet RPS compliance needs through smaller-scale renewable facilities that are less than 20 MW in size.

23. Currently, a utility must use the Tier 3 Advice Letter process when seeking Commission approval of a contract for the sale of RPS products.

24. Tier 2 Advice Letters may become effective after review by Energy Division Staff rather than after a vote by the full Commission.

25. In D.12-11-052, the Commission found it would not determine the portfolio content category of RPS resources until the utility submits an RPS compliance report and supporting information, as necessary, the Commission to determine the proper portfolio content categorization of the actual procurement and to make a compliance determination. This process does not happen at the time the Commission approves contracts.

26. The intent of the proposal in the April 5, 2012 ACR to replace the annual solicitation cycle with a two year cycle was to streamline the procurement process without sacrificing the transparency provided by the filing of annual procurement plans.

27. In directing the use of the PVC, the Commission noted that the PVC is an indicative rather than predictive tool and that the utilities remain responsible for the recommendations they make regarding projects necessary to meet their RPS Program requirements.

28. Further evidence is needed to understand the potential benefits of streamlining the contract amendment process relied upon by the Commission.

29. Regarding confidentiality of information related to RPS contracts, increased transparency is sought but it is unclear what additional information should be disclosed to the public.

30. The proposal in the April 5, 2012 ACR to require two, instead of one, Independent Evaluator reports sought to provide an early review of the procurement process of each utility.

31. Modifications are needed to the proposal in the April 5, 2012 ACR to utilize the RPS procurement process to minimize transmission costs. The proposal was to limit the amount of new generation procured in certain areas to ensure that costly network upgrades would not be triggered.

32. Pursuant to § 365.1 and D.11-01-026, ESPs are required to file annual procurement plans.

Conclusions of Law

1. The Commission is committed to continuing to monitor renewable procurement activities in Imperial Valley but declines the requests for additional oversight mechanisms based on, among other things, the continued robust procurement in the area.

2. A special Imperial Valley Bidder's conference should be optional for the utilities due to the lack of interest.

3. PG&E, SCE and SDG&E should not each assume a 1,400 MW MIC from Imperial Valley because a number of complications could result from such a requirement, such as utilities are likely to over-value imports from IID and equity concerns could arise regarding bids at other interties.

4. Consistent with PG&E's explanation, no preferences should be given to CAISO-interconnected projects or to projects otherwise interconnected.

5. It is reasonable for the utilities to solicit offers based on the preferences set forth in the 2012 RPS Procurement Plans.

6. The proposal presented in the April 5, 2012 ACR to standardize the variables to be included in the net market value (NMV) calculation is reasonable as it is consistent with past Commission decisions to promote transparency, further streamline the contracting process, and increase standardization across the utilities' LCBF methodologies.

7. The NMV calculation is a part of the utilities' LCBF methodologies. We make no determination on the value calculation of those NMV variables, except as noted in sections 4.2.3 (Integration Cost Adder) and 4.4.1 (Transmission Study Status Impact on Bid Valuation and Shortlist).

8. Based on the existing evidence, it is not reasonable to adopt additional variables to the NMV calculation.

9. It is reasonable to preserve the zero value integration cost adder in this proceeding because additional evidence should be required to make an alternative determination.

10. It is reasonable to authorize utilities to incorporate a provision into their pro forma agreements for use of a transmission upgrade cost cap and a related buy-down provision to limit the total RPS procurement costs to ratepayers.

11. It is reasonable to require the shortlist to expire 12 months after submission to the Commission because the benefits of being able to compare a contract's value and price to current solicitation data outweighs the concerns regarding the constraints imposed by a limited negotiation period.

12. Because utilities are permitted to receive two types of bids (energy-only or fully deliverable), we find it reasonable for the utilities to apply different sets of Time of Delivery factors to these two types of bids.

13. The TOD factors presented in the 2012 RPS Procurement Plans are reasonable although different from those applied in 2011 or in previous years.

14. The goals of the April 5, 2012 ACR to rely on the most current and accurate cost information at key decision points in the RPS procurement process and to maximize value to the ratepayer are achieved by requiring bids to obtain a minimum of a completed CAISO GIP Phase I (or equivalent) study to bid into the solicitation. These goals are further achieved by today's modification to the

pro forma agreement requiring parties to agree upon a cost cap for network upgrades.

15. The minimum size of projects participating in RPS Program solicitations should be remain 1.5 MW in an effort to keep the eligibility requirements as broad as possible for the RPS Program.

16. PG&E may include its Portfolio-Adjusted Value methodology in its 2012 solicitation protocol.

17. The Production Tax Credit and the Investment Tax Credit term in the pro forma agreement should be removed as it is likely that these federal tax credits will expire before contracts resulting from the 2012 RPS solicitation are executed.

18. PG&E's request to relax the credit rating requirements for financial institutions seeking to provide letters of credit for contracts resulting from the utility's RPS solicitations is reasonable because SCE and SDG&E currently apply these same credit rating requirements, there has been changes in the global economic situation, and PG&E continues to rely on credit-worthy institutions to provide letters of credit.

19. SCE's proposal to not hold a 2012 RPS solicitation is reasonable based on the explanation that, during the time period covered by the 2012 RPS Procurement Plans, SCE intends to address any unmet RPS compliance needs primarily through, among other methods, smaller-scale renewable facilities that are less than 20 MW in size.

20. SCE's proposal that it will consider offers for bilateral contracts during the time period covered by the 2012 RPS Procurement Plans is not reasonable because price reasonableness of such contracts is evaluated by comparison to the annual solicitation, which SCE will not hold.

21. Each utility remains responsible for meeting its RPS Program procurement requirements.

22. Because it is unclear whether the Tier 2 Advice Letter process will increase the utility's efficient management of its portfolio while maintaining sufficient ratepayer protections, the proposal for an expedited regulatory review process for excess REC and energy sales through the Tier 2 Advice Letter process should not be approved.

23. Consistent with D.11-12-052, the Commission's recent decision implementing the statutory amendments in Senate Bill 2 1X pertaining to portfolio content categories set forth in § 399.16(b)(1), the proposal that the Commission determine the portfolio content category of resources prior to the contract becoming effective should not be approved.

24. While the proposal to hold solicitations every two years, rather than annually, holds promise in terms of reducing the administrative burden resulting from annual filings, it should not be adopted at this time because it leaves a number of details undeveloped.

25. Based on the existing evidence, no changes to the PVC should be adopted and utilities should continue to use the PVC as an indicative tool and as one criterion in a utility's bid evaluation methodology.

26. Because further evidence is needed to understand the potential benefits of any efforts to streamline the process relied upon by the Commission to approve contract amendments, recommendations to change this process should not be approved at this time.

27. Because more analysis is required to comprehensively address confidentiality issues, especially with regards to changes appropriate for the RPS

Program framework under Senate Bill 2 1X, no changes should be made to the Commission's confidentiality rules at this time.

28. Because more analysis is needed to determine the benefits, if any, of requiring two, instead of one, Independent Evaluator reports, no modifications to the existing process should be adopted at this time.

29. Because more analysis is needed, the proposal presented in the April 5, 2012 ACR regarding minimizing transmission upgrade costs should not be addressed at this time.

30. The motion filed on April 17, 2012 by Shell Energy North America, (US), L.P and the Direct Access Customer Coalition for reconsideration of Assigned Commissioner's April 5, 2012 ruling should be denied.

O R D E R

IT IS ORDERED that:

1. Pursuant to the authority provided in Pub. Util. Code § 399.13(a)(1), the 2012 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 herein.

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 15 days of the mailing date of this decision pursuant to the RPS solicitation schedule adopted herein.

3. The Commission's Energy Division Staff shall continue to monitor development of projects under the Renewables Portfolio Standard (RPS) Program in the Imperial Valley according to the parameters set forth in Appendix A of Decision 09-06-018. In addition, Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company are directed to 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 Pub. Util. Code § 399.11 *et seq.* until directed otherwise by the Commission.

4. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) should assume a maximum import capability of no less than 1,400 megawatts for imports from the Imperial Irrigation District Balancing Authority Area to the California Independent System Operator as part of the evaluation of projects and bids within the 2012 Renewables Portfolio Standard (RPS) solicitation or future RPS solicitations. If PG&E, SCE, or SDG&E, nevertheless, assigns zero or near zero resource adequacy value to any project located in the Imperial Irrigation District Balancing Authority Area that bids in the 2012 RPS solicitation or future solicitations, that utility must present clear and convincing evidence why it did so as part of each request seeking Commission approval of any contract resulting from that solicitation. These directives shall apply to PG&E, SCE, and SDG&E in any subsequent RPS Procurement Plans unless otherwise directed by the Commission.

5. In the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company

(SDG&E) are authorized to include the varying preferences set forth in their 2012 RPS Procurement Plans, including, but not limited to, project location, delivery start dates, contract term lengths, and specific portfolio content categories. This authorization applies to PG&E and SDG&E in any subsequent RPS Procurement Plans unless otherwise directed by the Commission. While Southern California Edison Company (SCE) will not hold a 2012 solicitation, this authorization shall apply to any subsequent SCE RPS solicitations unless otherwise directed by the Commission.

6. In the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) shall modify their Least Cost, Best Fit methodologies to reflect the Net Market Valuation (NMV) calculation set forth below. We authorize the Commission's Energy Division Staff to propose modifications to the inputs to the NMV calculation through the Commission Resolution process. This methodology shall be employed by PG&E, Southern California Edison Company, and SDG&E in any subsequent RPS Procurement Plans unless otherwise directed by the Commission.

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

Where:
R = Net Market Value
A = Adjusted Net Market Value
E = Energy Value
C = Capacity Value
P = Post-Time-of-Delivery Adjusted Power Purchase Agreement Price
T = Transmission Network Upgrade Costs

G = Congestion Costs
I = Integration Costs
S = Ancillary Services Value

7. In the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) are not authorized to include language that refers to the use of non-zero integration cost adders, including any language in the Net Market Valuation portion of their Least Cost, Best Fit evaluation methodologies. This directive applies to future RPS Procurement Plans filed by PG&E and SDG&E unless otherwise directed by the Commission. This directive shall also apply to Southern California Edison Company in future RPS Procurement Plans unless otherwise directed by the Commission.

8. In the final 2012 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 San Diego Gas & Electric Company (SDG&E) shall incorporate terms into their respective pro forma agreements regarding termination rights and buy-down provisions in the event that the results of any interconnection study or agreement indicate that network upgrade costs will exceed a specific amount agreed to by seller and the utility. This directive applies to future pro forma agreements filed by PG&E and SDG&E unless otherwise directed by the Commission. While Southern California Edison Company will not hold a 2012 solicitation, this requirement shall apply to future use of its pro forma agreement unless otherwise directed by the Commission.

9. Beginning with the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, bids shortlisted by Pacific Gas and Electric Company (PG&E)

and San Diego Gas & Electric Company (SDG&E) shall be executed, if at all, within 12 months from the date utilities submit final shortlists to the Commission for approval. This expiration date is included in the schedule adopted herein. If that deadline is not met, the bid will be removed from the shortlist and the utility will not be permitted to execute a bilateral contract for the same project until after the initiation of a subsequent RPS solicitation. The project may be bid into any subsequent RPS solicitation. This directive applies to future RPS solicitations by PG&E and SDG&E unless otherwise directed by the Commission. While Southern California Edison Company (SCE) will not hold a 2012 solicitation, this requirement will apply to future SCE solicitations until otherwise directed by the Commission.

10. In the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company and San Diego Gas & Electric Company are authorized to use in their 2012 RPS solicitations two sets of Time of Delivery factors to reflect energy-only and fully deliverable status. This authorization only applies to the 2012 solicitation. Because Southern California Edison Company (SCE) will not hold a 2012 solicitation, SCE is not included.

11. In the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) shall modify their RPS bid solicitation protocols, as needed, to require bids have the minimum of a completed California Independent System Operator (CAISO) Generator Interconnection Procedures (GIP) Phase I (or equivalent) study to bid into the solicitation. This directive applies to future RPS Procurement Plans filed by PG&E and SDG&E unless otherwise directed by the

Commission. While Southern California Edison Company (SCE) will not hold a 2012 solicitation, SCE shall modify future bid solicitation protocols consistent with these requirements unless otherwise directed the Commission.

12. In the final 2012 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) may include its Portfolio-Adjusted Value methodology in its 2012 solicitation protocol and must include the Least Cost, Best Fit and Net Market Valuation methodologies. PG&E shall also provide the results of its Least Cost, Best Fit and Net Market Valuation methodologies with and without the Portfolio-Adjusted Value in any analysis of its 2012 solicitation provided to the Commission so that the Commission is able to adequately monitor the use of the Portfolio-Adjusted Value methodology.

13. In the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) shall remove the Tax Credit Mitigation Option Term or similar term from their pro forma agreements. Parties are not prohibited from agreeing to include this term in their contracts on a case-by-case basis. This directive applies to future RPS Procurement Plans filed by PG&E and SDG&E unless otherwise directed by the Commission. While Southern California Edison Company (SCE) will not hold a 2012 solicitation, SCE shall modify future bid solicitation protocols consistent with this requirement unless otherwise directed by the Commission.

14. In the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) may modify its pro forma agreement and any

existing contracts under the RPS Program to relax the threshold for banks to qualify as eligible to issue letters of credit for RPS contracts. Banks with credit ratings of "A-" from Standard & Poor's Financial Services, LLC or an "A3" rating from Moody's Investors Service, Inc., with an outlook designation of "stable" may participate in the RPS solicitations. This directive applies to future RPS Procurement Plans filed by PG&E unless otherwise directed by the Commission.

15. In the final 2012 Renewables Portfolio Standard Procurement Plan to be filed with the Commission pursuant to the schedule adopted herein, Southern California Edison Company shall remove the consideration of bilateral offers.

16. In the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company (PG&E) and San Diego Gas & Electric Company (SDG&E) may include a provision permitting the resource adequacy component of a contract to cover less than the entire term of the contract. This directive applies to future RPS Procurement Plans filed by PG&E and SDG&E unless otherwise directed by the Commission. While SCE will not hold a 2012 solicitation, SCE may modify future RPS Procurement Plans consistent with this requirement unless otherwise directed by the Commission.

17. In the final 2012 Renewables Portfolio Standard (RPS) Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, Pacific Gas and Electric Company's (PG&E), Southern California Edison Company's (SCE), and San Diego Gas & Electric Company's (SDG&E) final 2012 RPS Procurement Plans may include a competitive solicitation and bilateral contracts for the sale of excess RPS products from existing facilities and must rely on the Tier 3 Advice Letter process for the purpose of obtaining approval of contracts for the sale of excess bundled renewable energy and unbundled Recess This

directive applies to future RPS Procurement Plans filed by PG&E, SCE, and SDG&E unless otherwise directed by the Commission.

18. In the final 2012 Renewables Portfolio Standard Procurement Plans to be filed with the Commission pursuant to the schedule adopted herein, San Diego Gas & Electric Company (SDG&E) shall not include a requirement that the Commission determine or approve the portfolio content category classification as a precondition to the contract's effectiveness. This directive applies to future RPS Procurement Plans filed by Pacific Gas and Electric Company, Southern California Edison Company, and SDG&E unless otherwise directed by the Commission.

19. The following schedule is adopted for the 2012 Renewables Portfolio Standard (RPS) solicitation:

SCHEDULE FOR 2012 RPS SOLICITATION

LINE NO.	ITEM	NO. OF DAYS (cumulative)
1	Mailing of Commission decision conditionally accepting 2012 RPS Procurement Plans	0
2	PG&E, SCE and SDG&E file final 2012 RPS Procurement Plans	15
3	PG&E and SDG&E issue Requests for Offers (unless amended Plans are suspended by Energy Division Director by Day 25)*	25
4	PG&E and SDG&E notify Commission that bidding is closed	84
5	PG&E and SDG&E notify bidders of shortlist; no exclusivity agreements may be required before this date	144
6	PG&E and SDG&E submit shortlists to Energy Division and Procurement Review Group	154
7	PG&E and SDG&E file by Tier 2 advice letter (a) Evaluation Criteria and Selection Process Report and (b) Independent Evaluator's Report	184

LINE NO.	ITEM	NO. OF DAYS (cumulative)
8	PG&E and SDG&E 2012 RPS Solicitation Shortlists Expire	519
9	PG&E and SDG&E submit Tier 3 Advice Letters with contracts/PPAs for Commission approval	TBD

*The utility may adjust this date to a day after day 25, as necessary, without Commission approval.

19. 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 efficient administration of the 2012 Renewables Portfolio Standard solicitation process.

20. The Integrated Resource Plan Off-Year Supplement filed by PacifiCorp, a multi-jurisdictional utility, and the 2012 Renewables Portfolio Standard (RPS) Procurement Plans filed by the small utilities, Bear Valley Electric Service, a Division of Golden State Water Company, and California Pacific Electric Company, LLC. are accepted. The 2012 RPS Procurement Plans filed by Bear Valley Electric Service, a Division of Golden State Water Company, and California Pacific Electric Company, LLC. are deemed final and no further action is required. No further action is required pertaining to the Integrated Resource Plan filed by PacifiCorp.

21. Pursuant to Pub. Util. Code § 365.1(c)(1) and Decision 11-01-026, we accept the 2012 Renewables Portfolio Standard (RPS) Procurement Plans filed by electric service providers (ESPs), including 3 Phases Renewables, Calpine PowerAmerica-CA, LLC, Commerce Energy, Inc., Commercial Energy of California, Consolidated Edison Solutions, Inc., Constellation NewEnergy, Inc., Direct Energy Business, LLC, EDF Industrial Power Services (CA), LLC,

EnerCal USA, LLC, Gexa Energy California, LLC, Noble Americas Energy Solutions LLC, Pilot Power Group, Inc., Praxair Plainfield, Inc., Shell Energy North America (US), L.P., Tiger Natural Gas, Inc. We deem the 2012 RPS Procurement Plans filed by the ESPs as final and no further action is required.

22. The motion filed on April 17, 2012 by Shell Energy North America (US), L.P. and the Direct Access Customer Coalition for Reconsideration of Assigned Commissioner's April 5, 2012 ruling is denied.

23. Rulemaking 11-05-005 remains open.

This order is effective today.

Dated ________________, 2012, at San Francisco, California.