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)

COMMENTS OF NEXTERA ENERGY RESOURCES, LLC ON PROPOSED 2013 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS AND SCHEDULE

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On behalf of NextEra Energy Resources, LLC

July 12, 2013

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)

COMMENTS OF NEXTERA ENERGY RESOURCES, LLC ON PROPOSED 2013 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS AND SCHEDULE

I. INTRODUCTION AND SUMMARY

Pursuant to the May 10, 2013 "Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2013 Renewables Portfolio Standard Procurement Plans Pursuant to Public Utilities Code Sections 399.11 et seq. and Requesting Public Comments on a New Proposal" ("ACR"), and the extension of time granted by Administrative Law Judge ("ALJ") DeAngelis, NextEra Energy Resources, LLC ("NextEra")[1] submits these comments addressing the proposed 2013 Renewables Portfolio Standard Procurement Plans ("RPS Plans") submitted by Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE"), and San Diego Gas and Electric Company ("SDG&E").[2] These comments also address the schedule for approving the RPS Plans and commencing the 2013 RPS contracting process, and request modifications to the utilities' pro forma power purchase agreements ("PPAs").

The ACR states that the RPS Plans must "describe the overall plan for procuring RPS resources for the purposes of satisfying the RPS program requirements while minimizing cost and maximizing value to ratepayers," and sets forth specific requirements for information and

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[1] NextEra has a direct and substantial interest in the outcome of this proceeding. NextEra is the largest owner and operator of wind and solar generation resources in the United States with long-standing renewable generating assets in California, with nearly 1100 megawatts ("MW") of wind generation and 310 MW of solar generation in operation in California. NextEra also has 800 MW of solar generation under construction for commercial operation in 2013 and 2014 and another 290 MW in active development for commercial operation in 2015 and 2016. Through 2013, NextEra has invested $4.6 billion in renewable generating resources in California.

[2] ALJ DeAngelis granted the extension in an electronic mail message on May 23, 2013. The message confirms that comments are due July 12, 2013 and reply comments are due July 22, 2013.

analysis that must be included.[3] Each utility indicates in its RPS Plan that it is generally on track to meet RPS program requirements, while identifying and assessing numerous risk factors that could prevent or delay RPS compliance, including recurring obstacles associated with limited transmission availability, permitting and siting of projects, a heavily subscribed interconnection queue, developer performance issues, financing issues, technology risks, securing reliable and economic fuel supplies, curtailment, and the increasing proportion of intermittent resources in the portfolio.[4] Each utility proposes to conduct a 2013 RPS solicitation focused on procurement of resources that contribute to RPS compliance in the third compliance period or later.[5]

The RPS Plans generally present a reasonable approach for procuring incremental RPS resources to satisfy program requirements in the upcoming compliance periods. SCE's plan in particular demonstrates a good approach to procurement that will facilitate bringing new resources online in time to capture the expiring thirty percent Investment Tax Credit ("ITC") and the California property tax exemption, which together represent a substantial cost reduction to consumers. To realize these consumer benefits, the Commission's determination in this proceeding and the resulting contract approval process should be timed to result in approved PPAs by mid-2014. This timing is necessary to facilitate the late stage development and construction timelines that are required to achieve a 2016 commercial operation date.

Additional policy guidance and clarification is needed to ensure that procurement efforts focus on the most viable eligible renewable projects, and those best situated to meet RPS requirements while offering the most value for utility customers. Specifically, as explained further in Section II below:

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3 ACR, pp. 6 and 9-24.

4 *See* Pacific Gas and Electric Company's (U 39 E) 2013 Renewable Energy Procurement Plan – June 28, 2013 Draft (Public Version) ("PG&E RPS Plan"), pp. 1 and 43-55; Southern California Edison Company's (U 3380-E) 2013 Renewables Portfolio Standard Procurement Plan (Public Version) ("SCE RPS Plan"), Volume I, pp. 7 and 11-20; San Diego Gas & Electric Company (U 902 E) Draft 2013 Renewables Portfolio Standard Procurement Plan (Public Version) ("SDG&E RPS Plan"), pp. 5 and 18-23.

5 PG&E RPS Plan, p. 1 ("Based upon the compliance outlook provided in this Plan, PG&E's 2013 RPS Solicitation . . . will focus on cost-effective procurement intended primarily to position PG&E to be able to satisfy an ongoing 33% RPS requirement."); SCE RPS Plan, Volume I, p. 8 ("SCE plans to launch a 2013 RPS solicitation for projects with commercial operation dates of January 1, 2016 or later."). SDG&E's draft 2013 Request for Offers solicits projects with an online date no earlier than January 2020.

A. A clear policy is needed to encourage and facilitate the execution of contracts with cost competitive eligible renewable resources ("ERRs") that are currently operating under contracts due to expire in the coming years ("Existing Facilities"). Existing Facilities with active interconnection and transmission access and a proven operating record are valuable resources that do not expose utilities or their customers to the host of risks identified in the RPS Plans for new projects. This reduces the need to overprocure or build up surplus procurement to account for project failures and managing annual RPS compliance. Rather than replacing or displacing Existing Facilities and existing sites, as is likely to occur under the approach outlined in the RPS Plans, the Commission should adopt a policy specifically designed to maximize reliance on Existing Facilities and repowering existing sites that can contribute to RPS requirements. This can be done by requiring a preference or "tiebreaker" in favor of Existing Facilities and repowers if their offers provide economic value that is comparable to offers from new facilities.

B. Consistent with the theme of maximizing use of existing or committed infrastructure, it makes sense to favor projects with a Phase II Interconnection Study or better. Utilities should procure first from projects that will interconnect with and utilize transmission infrastructure that either exists or is well advanced in construction or permitting. Use of existing or advanced transmission upgrades reduces project risk and will be critical for solar projects to be able to commence operating by the end of 2016 and qualify for the expiring thirty percent ITC. There is a small window of opportunity to take advantage of projects that can qualify for the higher ITC and capture that value in their pricing for the benefit of utility customers. Accelerating the procurement process and focusing on the most advanced and viable projects, including from a transmission perspective, will be critical for the 2013 RPS procurement cycle.

C. Efforts also should be made to accelerate commencement of the 2013 RPS procurement process. This would help realize economic benefits from solar projects that can be online by the end of 2016 to qualify for the expiring ITC. Issuance of a Commission decision in October 2013, rather than later in the fourth quarter, would help accelerate the procurement timeline to allow sufficient time for project construction. Accelerating the schedule from RFO issuance to shortlisting also would help facilitate Commission approval of executed PPAs by mid-2014, which is necessary to allow adequate time for construction of ITC-eligible projects.

D. The pro forma PPAs require modification to facilitate efficient contracting and ensure that projects can be financed under current market conditions. Although the utilities have flexibility to accept changes to the pro forma PPAs that are requested by individual bidders, the contracting process would be much more efficient if the pro forma PPAs were updated ahead of time to reflect a common set of changes that are typically required by project lenders, and to reflect insurance coverage available in today's market. NextEra therefore asks the utilities to adjust their pro forma PPAs to reflect the changes provided in Exhibit A to these comments.

II. COMMENTS ON RPS PLANS, SCHEDULE AND PRO FORMA PPAS

A. A Clear Policy Is Needed To Facilitate And Encourage Re-Contracting Of Existing Facilities.

The ACR recognizes that "while new facilities are expected to become operational and provide generation necessary to achieve RPS goals, renewable facilities that exist and that are operating are an important resource and valuable investment."[6] The ACR specifies that RPS Plans must identify and provide information regarding contracts with ERRs that will expire in the next ten years.[7] The ACR also requires utilities to assess "the risk in the RPS portfolio in relation to RPS compliance requirements," and to include an assessment of "impacts to eligible renewable energy resource projects currently under contract."[8]

Although the ACR recognizes the inherent value of Existing Facilities, a clear policy is needed to ensure that these important resources will continue to contribute toward meeting RPS

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6 ACR, p. 21.

7 ACR, pp. 20-21.

8 ACR, p. 11.

goals either through re-contracting or repowering. This is evident in the RPS Plans, which do not assume that re-contracting will occur for Existing Facilities, other than through mandatory programs available only to small renewable projects.[9] Some statements in the RPS Plans also suggest that Existing Facilities are not needed because utilities have procured sufficient new resources to meet their RPS requirements in the coming years. Although Existing Facilities are eligible to participate in the upcoming 2013 RPS solicitations where they will compete for contracts against new projects, the RPS Plans suggest that procurement to date may have replaced or displaced Existing Facilities. For example, to match near-term deliveries from an Existing Facility with the identified near-term RPS need, Existing Facilities with upcoming expiration dates are requested by PG&E's RPS Plan to offer contract extensions or new contracts at discounted prices, *i.e.*, below current market value.[10] Existing Facilities with contracts expiring in later years are also encouraged to participate in an upcoming solicitation or face the risk that their window of opportunity to secure a long-term RPS contract could be lost, again suggesting that these Existing Facilities will be displaced by new projects.[11]

A clear policy is needed to encourage and facilitate active re-contracting and repowering of Existing Facilities so that they will continue to contribute to RPS requirements. As recognized in the ACR, Existing Facilities are valuable investments that have already been funded by utility customers through contracts that are now expiring. The Commission also should reinforce its preference for repowering of existing facilities. Since 2003, the Commission has had a clear preference for repowering old wind facilities, explaining that "the repowering of existing wind facilities in prime locations is a common-sense approach to increasing procurement of renewable energy with costs that should be lower than for new greenfield projects."[12] In 2005, the Commission reinforced its policy with regard to repowering, acknowledging the value of allowing bilateral negotiations for repowering projects and stating

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[9] *See e.g.,* PG&E RPS Plan, p. 111 ("As indicated in Appendix 3, PG&E's [residual net short] calculation results discussed in Section 6 assume no re-contracting" of Existing Facilities).

[10] PG&E RPS Plan, p. 77. SDG&E encourages Existing Facilities to provide bids for a price reduction coupled with an extended term. SDG&E RPS Plan, p. 9.

[11] PG&E RPS Plan, pp. 17-18.

[12] Decision 03-06-071, p. 58.

that the Commission expects utilities to "accord repowering a high priority, which would be reflected in actual contracts submitted for approval."[13]

Existing Facilities with contracts that expire in the next seven to ten years represent significant investment by the state in renewable resources and transmission infrastructure. NextEra recognizes that policy issues regarding existing renewable infrastructure are complicated, and that some renewable technologies may no longer be cost-competitive. Further, while many of the arguments favoring Existing Facilities and repowering existing sites are supported by quantitative metrics such as avoided transmission costs and renewable resource quality, other benefits are less easily quantified and require a policy decision that evaluates issues such as land use, lower production and procurement risk, and the inherent value of utilizing infrastructure that already exists. It should be noted that many of the first renewable sites in California are the best renewable sites in the state as recognized in the Commission's 2005 decision as noted above. Any policy, or lack thereof, that results in the decommissioning or dismantling of this infrastructure needs to be considered carefully.

Furthermore, the issues surrounding existing assets are complicated by the differences in resources and may be site-specific. For example, some resources are close to the end of their useful life and must be repowered or decommissioned. Others have a limited useful life and could re-contract for only a short term, such as five years. Other projects have had substantial capital investment and have many years of high production and re-contracting potential. Lastly, a considerable amount of the oldest resources are wind resources that are approaching the end of their useful life toward the end of the decade. These facilities will likely need to be repowered but it is currently difficult to bid these projects into solicitations given the longer-dated contract expiration and the uncertainty with the Production Tax Credit. In other words, it is premature to bid a repowering of these facilities, but the RPS Plans suggest that the sites are at risk of being replaced by new resources.

These situations raise critical points for consideration. The procurement process is currently designed to dial in procurement as close as possible to the year in which the RPS need exists. This is a challenging approach with such a large number of contracts with staggered expiration dates. The issues surrounding existing assets also raise questions as to whether the

[13] Decision 05-10-014, pp. 16-17.

RPS target represents a floor or a ceiling on procurement, and whether there is flexibility to overprocure in the short-term as contracts expire and repowering potential arises.

To avoid losing the previous investments by utility customers, utilities should be required to continue to use the Existing Facilities for as long as they are able to continue delivering RPS output at prices that are reasonably economic in light of other offers. A definitive policy is needed to reverse an apparent trend toward replacing Existing Facilities with new projects. It should not be necessary to demonstrate that a contract extension for an Existing Facility or a repowering of an existing site is necessary to meet an identified need for incremental RPS resources. To the contrary, Existing Facilities are currently serving an identified need for their output, as evidenced by the fact that the output counts toward meeting RPS obligations. In short, while NextEra agrees that existing resources or repowering of Existing Facilities should be price competitive, we do not believe the need analysis applied to new resources should be applied to resources currently filling a RPS need.

Replacement of Existing Facilities with all new projects would be wasteful of the existing investment, and potentially could force the mothballing or retirement of Existing Facilities before the end of their useful lives. The Commission should not allow this result without careful consideration of the cost and policy implications, which to date has not occurred. If the fleet of Existing Facilities will be replaced by new projects, this should be a deliberate decision supported by defined policy considerations, rather than the result of not having a policy on the continued use of Existing Facilities.

An Existing Facility or repowering of such facility should rank high in the evaluation process based on project viability, the existing site control, an active interconnection, existing deliverability status, resource adequacy, and an operating history to demonstrate expected performance. In light of these factors, continued use of Existing Facilities can reduce the need for incremental RPS procurement, potentially contributing to overall cost savings by deferring procurement of some new resources to a later date or adding to the utility surplus bank to manage RPS compliance. The utilities historically have procured resources above and beyond their needs to account for expected project failures and variability in the resource portfolio. Although the project failure rate has improved in recent years, voluntary overprocurement will continue under the RPS Plans, including through procurement of surplus resources that can be banked as mitigation against future risks of project failures.[14] Existing Facilities and repowering can help address this because they do not present the viability concerns that utilities must compensate for when they contract with new projects. Maximizing reliance on cost-effective Existing Facilities thus can reduce the need for surplus procurement of other RPS resources.

Rather than replacing or displacing Existing Facilities, as is likely to occur under the approaches outlined in the RPS Plans, the Commission should adopt a policy specifically designed to maximize reliance on Existing Facilities or repowering at those sites that can continue contributing to RPS requirements in a cost-effective manner. NextEra suggests that the Commission adopt a preference or "tiebreaker" in favor of Existing Facilities if their offers provide economic value that is comparable to offers from new facilities. Flexibility in contracting also must be available in light of the Existing Facility's contract expiration date, to avoid "gaps" in procurement that could leave Existing Facilities without a revenue stream. If its offer is competitive as compared with other offers, the Existing Facility should receive a new contract even if the delivery start date under the new contract occurs before the utility's identified incremental RPS need. This merely continues deliveries from a facility that already is counted toward the utility's RPS requirements.

It also makes sense to consider contract extensions or new contracts with all available Existing Facilities before engaging in voluntary overprocurement or creation of banked or surplus procurement. Additionally, it seems to make little sense to procure to bank new resources if an Existing Facility could be procured for the same time period. This is particularly important if a utility is procuring Category 2 or 3 products to create a banked surplus when a cost-effective existing renewable facility is available to serve the same purpose but provides a Category 1 product.

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[14] SCE RPS Plan, p. 8 ("SCE generally executes contracts for deliveries in excess of its renewable procurement need to account for the risk of project failure."); PG&E RPS Plan, pp. 83-84 (describing plans for a bank of surplus procurement as a voluntary margin of procurement designed to mitigate various risks, including risk of project failure or delay).

B. In Addition To Favoring Projects With Advanced Interconnection Documents, Utilities Should Prefer Projects Utilizing Transmission Infrastructure That Exists Or Is Advanced In Construction Or Permitting.

The RPS Plans appropriately focus on valuing projects that have a higher likelihood of achieving completion of both the project and the necessary transmission interconnection and upgrades. SCE's proposal to require projects to have a Phase II Interconnection Study or better will help focus procurement efforts on projects that are highly viable and likely to achieve commercial operation in a timely manner.

In addition to the transmission eligibility requirements proposed by SCE, there should be a requirement for considering the extent to which projects will utilize transmission infrastructure that is either already built, or well advanced in construction or permitting. Projects should rank higher in the bid evaluation process if they will interconnect with and utilize existing transmission infrastructure or transmission projects that are far along in the construction or permitting process. There should be a preference for such projects, as opposed to new projects requiring transmission upgrades that remain in the planning stage. Utilizing existing infrastructure is important considering the large transmission projects that have been approved and funded for construction to help facilitate achievement of California's RPS goals. A project capable of connecting to existing or advanced transmission lines will be much more likely to achieve commercial operation and deliverability milestones in a timely manner than a project proposing to interconnect at a location where upgrades remain in the planning stage. The evaluation process should recognize the distinction and value afforded by projects using existing or advanced transmission infrastructure.

Maintaining focus on the status of transmission upgrades in the 2013 solicitations is also important to obtain value that may be offered by solar projects capable of qualifying for the higher value ITC that currently is available only to projects that commence operating by the end of 2016. To meet this milestone and obtain the higher value ITC before it is no longer available, a project must be very advanced not only in its permitting process, but also in the interconnection and transmission upgrade process. Procurement therefore should focus on selecting projects interconnecting at a point where the interconnection and transmission upgrade work is likely to be completed in time to meet a 2016 online date.

C. The Procurement Process Should Commence As Soon As Possible To Capture Economic Value From Projects Capable Of Qualifying For Expiring Tax Benefits.

The ACR's procedural schedule indicates that issuance of a Commission decision on the RPS Plans and issuance of the 2013 RPS solicitations both will occur during the fourth quarter of 2013.[15] As explained above, timing is important in this round of solicitations. Only solar projects that can achieve an online date by the end of 2016 can capture the expiring ITC benefits and California property tax benefits. These incentives result in a significant discount to the price that consumers pay for an eligible project's output.

To begin operating in 2016, and assuming a one- to two-year construction period depending on the size of the project, a project intending to qualify for the higher ITC value before it expires will need to start construction in 2014 or 2015. Even if the solicitations are launched by the end of this year as planned, there is very little time to conduct the solicitation process and finalize and obtain approval for the winning contracts. For the development and construction timeline to support a 2016 online date, developers will require entry into contracts in early 2014 and approval by the Commission by mid-2014. Delay in completing the solicitation, signing contracts, and contract approval will cut into the scarce time that remains for late stage development and project construction. In comparison, contracts that are to be approved in the fourth quarter of 2014 resulting from the fifth RAM solicitation will provide projects two years to meet an online date in late 2016. Therefore, urgency is needed to provide at least an equal amount of time for completion of projects that are expected to exceed the 20 MW level.

If at all possible, it would be helpful to accelerate issuance of a Commission decision on the RPS Plans to ensure that the solicitations commence this year as planned. Issuance of a decision early in the fourth quarter – in October – may help achieve this timing. Accelerating the decision seems feasible given that the issues raised in this year's RPS Plans are fewer and less complex than in previous years.

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15 ACR, Attachment A.

D. The Pro Forma PPAs Require Modification To Facilitate Efficient Contracting And Ensure Project Financeability.

NextEra previously submitted comments requesting certain changes to the pro forma PPAs that are used in the Renewable Auction Mechanism ("RAM") process.[16] NextEra explained that its recommended changes were needed to align the RAM pro forma PPA, which is not negotiable, with the expectations of project lenders to facilitate efficient contracting and ensure that winning projects can be financed under current market conditions. NextEra also requested changes to the insurance provisions to align with the insurance products that are currently available in the market.

Many of NextEra's comments on the RAM contracts also apply to the pro forma PPAs that are included in the RPS Plans.[17] NextEra recognizes that utilities have flexibility to agree to PPA modifications requested by bidders in the RPS solicitation process. The contracting process would be much more efficient, however, if the pro forma PPAs were updated ahead of time to reflect a common set of changes that are typically required by project lenders. Similar efficiency benefits would result if the insurance provisions could be adjusted to reflect the insurance products that are presently available to project developers. PG&E's revised pro forma PPA heightens the importance of the insurance requirements by now specifying in Section 10.10 that a seller's obligations to obtain and maintain the required insurance "constitute material obligations of the Agreement." But Section 10.10(d)(i) unnecessarily requires sellers to obtain "delayed opening coverage" for a project. This requirement should be eliminated to prevent unnecessary cost to the seller given that PG&E has adequate protection against a delayed start date due to the requirement for sellers to post development security and pay PG&E delay damages if project completion is delayed. Additionally in Section 10.10(d)(i), PG&E's added requirement "with sublimits as appropriate," should be supplemented with the phrase "that are reasonably available commercially." The requirement in Section 10.10(d)(ii) for insurance covering "the full replacement cost of the property (with sublimits as appropriate)" also should be modified to require only that coverage be sufficient to repair and return the plant to operation.

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16 *See* NextEra's Comments on Draft Resolution E-4582 dated as of April 29, 2013, and NextEra's Comments on Draft Resolution E-4546 dated as of October 22, 2012.

17 NextEra appreciates PG&E's incorporation into its RPS pro forma PPA of two changes to the insurance provisions that NextEra suggested in its RAM comments.

The PPA provides adequate protection for PG&E in the event of seller's non-performance, including by requiring seller to post substantial collateral securing its obligations during the delivery term.

In SCE's pro forma PPA, NextEra supports the majority of the updates in the insurance section, with two exceptions. SCE's addition of Section 10.11(c), which requires insurance policies to be written on a "per project" or "per contract" basis," should be modified to more accurately reflect common practice in the industry. NextEra purchases insurance on a master policy basis and suggests that applicable coverage can be provided under a PPA without having an explicitly separate policy. Additionally, whereas NextEra takes no issue with providing a certificate of insurance to SCE, SCE's addition of the requirement to provide "the entire policy forms, including endorsements" is unnecessary and puts sellers in the position of disclosing confidential, commercially sensitive information. NextEra requests the deletion of the added requirement.

NextEra's recommended changes with respect to financeability issues in the pro forma PPAs are summarized in the attached Exhibit A. NextEra requests that the utilities adjust their pro forma PPAs to reflect those recommendations.

III. CONCLUSION

NextEra appreciates the opportunity to submit these comments.

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July 12, 2013

VERIFICATION

I, Kerry Hattevik, am the Regional Director of West Government Affairs for NextEra Energy Resources, LLC. I am authorized to make this Verification on its behalf. I declare under penalty of perjury that the statements in the July 12, 2013 **COMMENTS OF NEXTERA ENERGY RESOURCES, LLC ON PROPOSED 2013 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS AND SCHEDULE** are true of my own knowledge, except as to the matters which are therein stated on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.

Dated as of July 12, 2013.

/s/ Kerry Hattevik

Kerry Hattevik
Regional Director of West Government Affairs
NextEra Energy Resources, LLC

EXHIBIT A: Summary of Requested Changes to the Pro Forma PPAs

Financeability Issue	PG&E	SCE	SDG&E
1. Non-negotiable lender consent form	<u>**Section 10.6(b)**</u>: Current PG&E contract provides for PG&E to consent to an assignment for financing purposes "in a form substantially similar to the Form of Consent to Assignment attached" to the PPA as Appendix XI, but limits negotiation of terms "including extension of any cure periods or additional remedies for financing providers." <u>**NEE PROPOSAL**</u>: Similar to SCE and SDG&E PG&E shall in good faith negotiate with the Seller and Lender to agree upon a consent to collateral assignment of the contract. (Importance – Depending upon market conditions, Lenders require certain flexibilities in their cure rights to avoid unnecessary direct performance/financial obligations in the event of a Seller's default.)	<u>**Section 10.05**</u>: In connection with any financing or refinancing of the Generating Facility by Seller, SCE shall in good faith work with Seller and Lender to agree upon a consent to collateral assignment of this Agreement. <u>**NEE PROPOSAL**</u>: None	<u>**Section 13.2**</u>: In connection with any financing or refinancing of the Project by Seller, Buyer shall in good faith negotiate and agree upon a consent to collateral assignment of this Agreement in a form that is commercially reasonable and customary in the industry. <u>**NEE PROPOSAL**</u>: None
2. Short lender cure periods in the event of Seller's default	<u>**Appendix XI – Form of Consent to Assignment, Section 4(b):**</u> For purposes of this Agreement "Additional Cure Period" means (i) with respect to a monetary default, ten (10) days in addition to the cure period (if any) provided to Seller in the Assigned Agreement, and (ii) with respect to a non-monetary default, thirty (30) days in addition to the cure period (if any) provided to Seller in the Assigned Agreement. <u>**Section 4(d):**</u> If possession of the Project (as defined in the Assigned Agreement) is necessary for Financing Provider to cure an Event of Default and Financing Provider commences foreclosure proceedings against Seller within thirty (30) days of receiving notice of an Event of Default from PG&E or Seller, whichever is received first, Financing Provider shall be allowed a reasonable additional period to complete such foreclosure proceedings, such period not to exceed ninety	<u>**Section 10.05(c)**</u>: Lender will have the right to cure an Event of Default on behalf of Seller, only if Lender sends a written notice to SCE before the end of any cure period indicating Lender's intention to cure. Lender must remedy or cure the Event of Default within the cure period under this Agreement; provided, such cure period may, in SCE's sole discretion, be extended by no more than an additional one hundred eighty (180) days. <u>**NEE PROPOSAL**</u>: See NEE's proposal to PG&E. This also ensures that all lender cure periods are the same for all IOU contracts in California. (Importance – Longer lender cure periods ensures each participating lender has flexibility to meet its own internal	<u>**NEE PROPOSAL**</u>: See NEE's proposal to PG&E. This also ensures that all lender cure periods are the same for all IOU contracts in California. (Importance – Longer lender cure periods ensures each participating lender has flexibility to meet its own internal procedures/schedules to obtain necessary approvals from its committees.)

Financeability Issue	PG&E	SCE	SDG&E
	(90) days. **NEE PROPOSAL**: To increase cure period for monetary default from 10 days to 30 days and for non-monetary default from 30 days to 60 days, and up to 90 days if cure is being pursued diligently. Regarding foreclosure, if foreclosure proceedings cannot reasonably be cured within the 90 day period such period shall be extended up to 365 days. (Importance – Longer lender cure periods ensures each participating lender has flexibility to meet its own internal procedures/schedules to obtain necessary approvals from its committees.	procedures/schedules to obtain necessary approvals from its committees.)	
3. Short cure period for Force Majeure (FM) Event	**Section 11.1(a)(i)**: Force Majeure Project Failure occurs if after the Commercial Operation Date, the Project fails to deliver at least forty percent (40%) of the Contract Quantity to the Delivery Point for a period of twelve (12) consecutive rolling months following a Force Majeure event that materially and adversely impacts the Project, unless Seller submits and pursues a mitigation plan. **NEE PROPOSAL**: None	**Section 5.04**: Either Party may terminate this Agreement on Notice, which will be effective five (5) Business Days after such Notice is provided, if (a) an event of Force Majeure extends for more than three hundred sixty-five (365) consecutive days and materially and adversely affects the operations of the Claiming Party, or (b) the Generating Facility is destroyed or rendered inoperable by a Force Majeure, and an independent, third party engineer determines in writing that the Generating Facility cannot be repaired or replaced within twenty-four (24) months after the first day of such Force Majeure. **NEE PROPOSAL**: None	**Section 5.8**: This Agreement may be terminated by the non-claiming Party with no further obligation to the Force Majeure claiming Party if a Force Majeure event prevents the performance of a material portion of the obligations of the Force Majeure claiming Party hereunder and such Force Majeure event is not resolved within eight (8) months after the commencement of such Force Majeure event. **NEE PROPOSAL**: Termination cure period of 8 months for a Force Majeure event is very short. SDG&E's cure period should be consistent with PG&E (12 consecutive rolling months following a Force Majeure event that materially and adversely impacts the project) or SCE (365 consecutive days following a Force Majeure event that materially and adversely impacts the project).
4. Change of Control	**Section 10.6(c):** Any direct or indirect change of control of Seller (whether voluntary or by operation of Law) shall be deemed an assignment and shall require the prior written consent of Buyer, which consent shall not be unreasonably withheld.	**Section 10.04(b):** Any direct or indirect change of control of Seller (whether voluntary or by operation of law) will be deemed an assignment and will require the prior written consent of SCE, which consent shall	**Section 13.2:** Neither Party shall assign this Agreement or its rights hereunder without the prior written consent of the other Party, which consent shall not be unreasonably withheld. For purposes hereof, the transfer of more than fifty percent (50%) of the

Financeability Issue	PG&E	SCE	SDG&E
	<u>NEE PROPOSAL</u>: NEE is proposing that PG&E adopt the language currently used in the RAM contract: Except in connection with public market transactions of the equity interests or capital stock of Seller or Seller's Affiliates, Seller shall provide Buyer notice of any direct change of control of Seller (whether voluntary or by operation of Law).	not be unreasonably withheld. **<u>NEE PROPOSAL</u>**: NEE is proposing to use PG&E's RAM change of control language which provides that except in connection with public market transactions of the equity interests or capital stock of Seller or Seller's Affiliates, Seller shall provide Buyer notice of any direct change of control of Seller (whether voluntary or by operation of Law).	equity ownership or voting interest of Seller (or any parent entity holding directly or indirectly at least fifty percent (50%) of the equity ownership or voting interest of Seller if such interest constitutes more than twenty percent (20%) of the fair market value of the assets of such parent entity) to a person that is not an Affiliate of Seller shall also constitute an assignment of this Agreement requiring Buyer's prior written consent. **<u>NEE PROPOSAL</u>**: NEE is proposing to use PG&E's RAM change of control language which provides that except in connection with public market transactions of the equity interests or capital stock of Seller or Seller's Affiliates, Seller shall provide Buyer notice of any direct change of control of Seller (whether voluntary or by operation of Law).
5. Non-Standard Transfer Tax Provisions	**<u>Section 9.2:</u>** Seller shall pay or cause to be paid all taxes imposed by any Governmental Authority ("Governmental Charges") on or with respect to the Product or the Transaction arising at the Delivery Point, including ad valorem taxes and other taxes attributable to the Project, land, land rights or interests in land for the Project. Buyer shall pay or cause to be paid all Governmental Charges on or with respect to the Product or the Transaction from the Delivery Point. **NEE PROPOSAL:** NEE is proposing to use the SCE transfer tax provision which specifies that Seller pays taxes arising before the Delivery Point, and Buyer pays taxes arising at and from the Delivery Point. This is consistent with the industry standard.	**<u>Section 9.02:</u>** Seller shall pay or cause to be paid all taxes imposed by any Governmental Authority ("Governmental Charges") on or with respect to the Metered Amounts (and any contract associated with the Metered Amounts) arising before the Delivery Point, including ad valorem taxes and other taxes attributable to the Generating Facility, land, land rights or interests in land for the Generating Facility. SCE shall pay or cause to be paid all Governmental Charges on or with respect to the Metered Amounts at and from the Delivery Point. **<u>NEE PROPOSAL</u>**: None	**<u>Section 9.2:</u>** Seller shall pay or cause to be paid all taxes imposed by any governmental authority ("Governmental Charges") on or with respect to the Product or the transaction under this Agreement arising prior to and at the Delivery Point, including, but not limited to, ad valorem taxes and other taxes attributable to the Project, land, land rights or interests in land for the Project. Buyer shall pay or cause to be paid all Governmental Charges on or with respect to the Product or the transaction under this Agreement from the Delivery Point. **NEE PROPOSAL:** NEE is proposing to use the SCE transfer tax provision which specifies that Seller pays taxes arising before the Delivery Point, and Buyer pays taxes arising at and from the Delivery Point. This is consistent with the industry standard.