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Ratesetting
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Decision **ALTERNATE PROPOSED DECISION OF COMMISSIONER SANDOVAL (Mailed 5/6/2016)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to improve distribution level interconnection rules and regulations for certain classes of electric generators and electric storage resources.	Rulemaking 11-09-011 (Filed September 22, 2011)

ALTERATE DECISION INSTITUTING COST CERTAINTY, GRANTING JOINT MOTIONS TO APPROVE PROPOSED REVISIONS TO ELECTRIC TARIFF RULE 21, AND PROVIDING SMART INVERTER DEVELOPMENT A PATHWAY FORWARD FOR PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY

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ALTERATE DECISION INSTITUTING COST CERTAINTY, GRANTING JOINT MOTIONS TO APPROVE PROPOSED REVISIONS TO ELECTRIC TARIFF RULE 21, AND PROVIDING SMART INVERTER DEVELOPMENT A PATHWAY FORWARD FOR PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, AND SAN DIEGO GAS & ELECTRIC COMPANY

Summary

Today's decision grants joint motions improving Electric Tariff Rule 21 to: (1) provide earlier and more reliable interconnection cost information to electric generation developers and (2) set forth the process for analyzing requests for interconnection of electricity storage devices. These motions are the result of an exemplary collaborative process among the parties, all of whom are to be commended for their tireless work. Today's decision also grants a cost envelope pilot policy for interconnection cost certainty.

This proceeding is closed.

1. Background

The Commission initiated Rulemaking (R.) 11-09-011 on September 22, 2011 to review and, if necessary, revise the rules and regulations governing interconnecting generation and storage resources to the electric distribution systems of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E). The utilities' rules and regulations pertaining to the interconnection of generation are generally set forth in Electric Tariff Rule 21.

On September 20, 2012, the Commission issued Decision (D.) 12-09-018 which adopted a settlement agreement that included revisions to Electric Tariff Rule 21 and provided a separate Generator Interconnection Agreement for Exporting Generating Facilities and Exporting Generating Facility Interconnection Request. The revisions to Electric Tariff Rule 21 focused on the interconnection study process. The settlement agreement required that each utility revise its Electric Tariff Rule 21 to assign all interconnection requests to either the "Fast Track" - a screen-based, streamlined review process for net energy metering, non-export, and small exporting facilities or the Detailed Study with three study processes for more complicated generating facilities.

On December 18, 2014, the Commission issued D.14-12-035 which granted joint motions proposing revisions to Electric Tariff Rule 21 to require "smart" inverters for PG&E, SCE, and SDG&E. The purpose of inverters is to convert direct current (DC) from the generating resource to the voltage and frequency of the alternating current (AC) distribution system. Wind and photovoltaic resources produce DC, and therefore need inverters, while hydroelectric and biomass generating units, which produce AC, do not. Generally, in California, about 90% of small scale renewable generation is connected to the distribution grid through inverters.

The Commission agreed with the moving parties that bringing the benefits of today's "smart inverters" to California required changes to Electric Tariff Rule 21 and, in D.14-12-035, the Commission adopted the revisions recommended by the Smart Inverter Working Group in their January 2014 "Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources." The Commission granted the parties' request and ordered the utilities to file Tier 1 Advice Letters making the following changes to their respective Electric Tariff Rule 12:

a. Anti-Islanding Protection: Revise Electric Tariff Rule 21, Section H.1.a.(2) to reflect proposed new voltage ride-through settings;

b. Low and High Voltage Ride-Through: Revise Electric Tariff Rule 21, Section H.1.a.(2) and Table H.1 to reflect proposed new default voltage ride-through requirements;

c. Low and High Frequency Ride-Through: Revise Electric Tariff Rule 21, Section H.1.a.(2) and R21 Table H.2 to reflect proposed new frequency ride-through settings;

d. Dynamic Volt-Var Operation: Revise Electric Tariff Rule 21, Sections H.2.a, H.2.b, H.2.i and R21 table H.1 to reflect proposed new dynamic volt/var operations requirements;

e. Ramp Rates: Add new Electric Tariff Rule 21 subsection within Electric Tariff Rule 21, Section H to include proposed new ramp rate requirements;

f. Fixed Power Factor: Revise Electric Tariff Rule 21, Section H.2.i to reflect the proposed new fixed power factor requirements; and

g. Soft Start Reconnection: Revise Electric Tariff Rule 21, Section H.1.a.(2) to reflect proposed new reconnection by soft-start method.

On August 6, 2015, the assigned Commissioner and assigned Administrative Law Judge (ALJ) convened a Status Conference to determine the state of the parties' work on the issues of: (1) behind-the-meter storage interconnection requests, and (2) interconnection cost certainty. The parties appeared and presented the results of their meetings, which have been facilitated by Staff from the California Public Utilities Commission's Energy Division.

On August 19, 2015, the assigned ALJ issued a ruling setting forth the schedule proposed by the parties and approved by the assigned Commissioner and assigned ALJ:

DATE	EVENT
August 6, 2015	Pursuant to Rule 13.14(a), record submitted for decision by the Commission on the issue of the Utilities' fixed cost option proposal versus parties' alternative cost envelope proposal.
August 24, 2015	Clean Coalition distribute to service list Cost Guide Proposal.
August 31, 2015	Solar City and California Solar Energy Industries Association distribute to service list Pre-Application Report Expansion Proposal.
August 31, 2015	Utilities, and other parties should they so desire, distribute to service list written proposal on Storage Load Issues, including any changes to Rule 21 screens.
September 14, 2015	Utilities and Solar City, and other parties should they so desire, distribute to service list Non-Exporting Storage Proposal.
Before September 30, 2015	Utilities conduct informational webinar providing an overview of the process for reviewing storage projects pursuant to Rule 21.
September/October 2015	Energy Division Staff to facilitate workshops on issues, including follow-ups as needed.
November 9, 2015	Joint Motion Requesting Commission action on Cost Certainty Issues filed and served, alternative motions, if any, also filed and served.
November 4, 2015	Joint Motion Requesting Commission action on Storage Interconnection issues filed and served, alternative motions, if any, also filed and served.
As provided in Rule 11 of the	Responses and replies, if authorized, to motions.

Commission's Rules of Practice and Procedure (Rules).	
With the filing of the last response or reply to the motions.	Remaining issues in proceeding Submitted for decision by Commission Pursuant to Rule 13.14(a).

1.1. Joint Motion on Cost Certainties

In compliance with the August 2015 Ruling, Clean Coalition, SolarCity and California Solar Energy Industries Association distributed their proposals as directed and the Energy Division hosted a Workshop on the two cost certainty issues on October 2, 2015. Subsequently, on October 20, 2015, the Energy Division facilitated a second, follow-up workshop on the Cost Certainty Issues.

As a result of the workshops, the parties developed a set of agreed-upon principles to support interconnection efficiency and transparency. On November 9, 2015, SCE, SDG&E, PG&E, California Solar Energy Industries Association, Clean Coalition, CODA Energy and Interstate Renewable Energy Council, Inc., filed and served their joint motion proposing Pre-Application Report Enhancements and the development of a Unit Cost Guide. The moving parties explained that the Unit Cost Guide will give generation developers a readily available price list of typical interconnection facilities and equipment, and that adding specific data, with associated costs and timing, to the Enhanced Pre-Application report will also give generation developers better cost information.

Unit Cost Guide. The purpose of Unit Cost Guide is additional cost transparency in support of generation interconnection. Based upon the numerous discussions and workshops, the moving parties requested that the Commission direct the Utilities to prepare and issue an annual Cost Guide that conforms to a set of agreed-upon principles. The Guide Implementation Principles are set forth in complete detail in Attachment A to today's decision.

The Cost Guide Implementation Principles provide for the Utilities to develop the Guide within 90 Calendar Days of the Commission's decision. Each Utility will publish a Cost Guide for facilities generally required to interconnect generation to their respective Distribution systems, but the Utilities will coordinate to develop a consistent Cost Guide format. The Cost Guide, however, will not be binding for actual facility costs. The Cost Guide will reflect a forecasted annual adjustment for five years to provide estimates for future procurement timing. The Utilities will include illustrative scenarios reflecting stakeholder input to assist in understanding and readability of the guide, and will describe various requirements for interconnection facilities and distribution upgrades; an annual proposed stakeholder review process can act as a forum to discuss the usefulness of such scenarios and provide for updates. The Cost Guide will set forth assumptions used in the calculations in a format similar to that used by the California Independent System Operator, and will provide utility operation and maintenance along with recovery cost calculation method calculations.

The Utilities will update their Cost Guides annually. Prior to posting updates to the Cost Guide, the Utilities will meet and confer with stakeholders to obtain comment on proposed revisions pursuant to a schedule set forth in the Principles. Overall, the Cost Guides developed by the Utilities will not replace any project-specific study costs, but rather, the Cost Guide is intended to be used as a point of reference for projects that are considering the existing study processes.

Enhanced Pre-Application Reports. The moving parties explained that enhancement of the existing Rule 21 Pre-Application Report would address interconnection customer data needs while ensuring overall tariff consistency and achieving the underlying purpose and intent of the existing Pre-Application Report. The complete set of all requested enhancements to the Rule 21 Pre-Application Report is set forth in Attachment B to today's decision.

The requested enhancements rename the current report "Standard Pre-Application Report" and create a new "Enhanced Pre-Application Report" that permits requests for more detailed data points/packages on a project-specific basis. Overall, the goal is for the Utilities to move towards a single application process for both the Standard and Enhanced Pre-application Reports in order to promote simplicity and streamlined procedures.

Attachment B shows the anticipated method and pricing for the data items available within the Enhanced Pre- Application Report. While the (Standard) Pre-Application Report in its current form and pricing will remain an Available option for interconnection customers, the Enhanced Pre-Application Report data items will be available to an Interconnection Customer based upon specific cost and timing, reflective of the scope of work required for these new enhanced report data items. The Utilities intend to automate as much of the Standard and Enhanced Pre-application request form and related process as is feasible and appropriate.

On November 23, 2015, the Commission's Office of Ratepayer Advocates (ORA) responded in support of the joint motion, and commended the Utilities and other parties for the extensive discussion during the August and September workshops. ORA stated that the Joint Parties had worked hard to reach consensus on the Joint Motion.

ORA also recommended that the Commission direct the Utilities to track the time it takes to prepare the Enhanced Pre- Application Report and the costs associated with its preparation. This information should be used to refine the fee charged to developers in its preparation and avoid undue shifting of these costs to ratepayers such that future updates to the Enhanced Pre-Application Report will reflect the actual price incurred to prepare it.

Solar City also supported the joint motion and noted that there are still outstanding issues that may require additional reforms to Rule 21 and that this or another proceeding should be open to address those issues.

1.2. Joint Motion on Behind the Meter Energy Storage

On November 18, 2015, PG&E, SCE, SDG&E, the Interstate Renewable Energy Council, Inc., the Clean Coalition, Robert Bosch LLC and Stem, Inc. filed and served a joint motion setting forth proposed revisions to Electric Tariff Rule 21 to address interconnection of behind-the-meter, non-exporting energy storage. The joint motion requested Commission authorization for the following revisions to the interconnection process for these storage resources:

- Insert clarifications regarding the treatment of load from energy storage charging to the Rule 21 tariff;
- Allocate costs for upgrades that are attributable to both the load and generation impacts of storage by prioritizing the load impacts before the generation impacts;
- Provide additional detail on energy storage charging load processes through a public Guide; and
- Modify the Interconnection Application and Agreement to capture energy storage load information for the applicable energy storage agreements.

Furthermore, parties to the Joint Motion propose a process for moving forward on the following additional items pertaining to energy storage interconnection that were discussed during the workshops but that require additional review and consideration by the stakeholders:

- Define criteria and propose an implementation process for an expedited interconnection process for non-exporting storage;
- Address the use of AC/DC converters (or other defined term as agreed upon) and specify the certification of and Rule 21 process applicable to such technology that would allow Generating Facilities utilizing such equipment to immediately pass Rule 21 Fast Track Initial Review; and
- Continue discussions regarding the criteria and certification process for providing an Inadvertent Export option for Rule 21 Fast Track Initial Review based on advanced inverter functionality.

The parties' specific recommendations are set forth in Attachment C to today's decision. The parties also requested that the Commission identify a forum in which additional identified issues related to the interconnection of energy storage will be addressed.

On December 2, 2015, ORA responded in support of the motion to revise Electric Tariff Rule 21 to address interconnection of behind-the-meter, non-exporting energy storage. ORA commended the moving parties for their efforts during the September and October workshops. In addition to the requests set forth in the motion, ORA recommended that the Commission direct the Utilities to record the monetary allowances permitted under Rules 15 and 16 and report back to the Commission the total costs, annually. ORA explained that the allowances of Rules 15 and 16 are allocated to ratepayers and such a report would help determine rate-payer impact in using these rules. Additionally, the report should also include the amount collected via deficiency billing to help to determine the effectiveness of using Rules 15 and 16 allowances for storage interconnection, and to determine if using Rules 15 and 16 is the proper mechanism for cost allocation.

On December 3, 2015, California Solar Energy Industries Association, California Energy Storage Alliance, and SolarCity Corporation each filed responses to the motion. All parties supported the motion. The California Solar Energy Industries Association supported opening a new proceeding for the remaining issues. The California Energy Storage Alliance argued for a "no review necessary" option for energy storage systems under a certain defined energy storage threshold and for energy storage systems operating under standardized operational modes. SolarCity supported the motion but also asked that the interconnection process guide be submitted initially via a Tier 2 advice letter with subsequent modification submitted via a Tier 1 advice letter. Solar City also argues that the operational modes should be expanded to include a "constrained grid charging mode" through which the storage system owner/operator would limit charging to time periods and levels that do not result in system upgrade requirements, leading to more systems qualifying for a cursory review as part of the Rule 21 Fast Track Initial Review Timeline. SolarCity also supported creating an ongoing forum for consideration of a number of outstanding issues related to interconnection.

1.3. Interconnection Cost Certainty

On April 1, 2015, SCE, SDG&E, and PG&E (the Utilities) jointly filed a motion with proposed revisions to Electric Tariff Rule 21 to enhance the predictability and reliability of interconnection cost estimates, referred to as "cost certainty," by inserting a Fixed Price Option into Tariff Rule 21.

The Utilities explained that their proposed fixed price option will be available to a significant portion of the Interconnection Requests that pass the

Fast Track Interconnection Review Process or qualify for the Independent Study Review Process. Qualifying projects must not only meet the requirements for Fast Track Interconnection Review Process, but must also not require substation upgrades, and require less than $500,000 in upgrades to the electric system. The Utilities stated that projects that do not meet these eligibility requirements are high-impact projects that are likely to require significant distribution upgrades, network upgrades, and/or are dependent upon facilities triggered by earlier queued projects. The Utilities contended that they lacked sufficient data on high-impact projects to extend any fixed price option to such projects.

The fee for the fixed price option is $10,000, which is non-refundable. The Utilities stated that this fee is necessary to pay for the additional resources required to prepare the fixed price estimate.

The Utilities stated that Interconnection Requests that meet the eligibility criteria may opt for the Fixed Price Option whereby the Utility will prepare a Fixed Price Option Estimate which includes an estimate of the costs to interconnect a generating facility with certain specified elements will be offered by the Utility on a fixed price basis. In this way, for all interconnection applicants proceeding under the Fixed Price Option, such specified elements included in the fixed price will be carried through to the Interconnection Agreement and will not be subject to later true-up to actual cost.

Within 20 days following selection of the Fixed Price Option and payment of the Fixed Price Option fee, the interconnection applicant must provide additional technical details, and 60 business days later the Utility will complete the fixed price that will be offered to the interconnection applicant and will include a description of any cost elements not included in the fixed price. Such excluded cost elements are costs of required environmental studies, environmental mitigation, permits, or easements related to the construction and installation of the Utility's facilities, which are excluded due to the unpredictability and potential magnitude of these costs. Accordingly, the interconnection applicant will be responsible for the actual cost of these excluded items.

In the cost certainty motion, the Utilities proposed, "…that any difference, either due to overcollection or undercollection, would be trued up in customer rates through the normal General Rate Case (GRC) capital work order process." No further details on this proposal were included in the motion or the utilities' proposed revisions to Tariff Rule 21.

On April 16, 2015, the assigned ALJ ruled that additional information was needed for the parties and the Commission to evaluate this proposal, and directed that no later than May 1, 2015, the Utilities shall file and serve a supplement to their April 1, 2015, motion setting forth details of this ratemaking proposal. The Utilities were required to describe how differences in project interconnection costs, either over or under-collections, would be treated for purposes of a utility's plant-in-service and regulated rate base. The Utilities were also required to explain their justification for including any such costs in the regulated revenue requirement, and particularly address the incentives created by their ratemaking proposal and customer rates.

On May 8, 2015, the Utilities responded and stated that their Fixed Price Option is designed to minimize any difference between the fixed price given to an interconnection applicant and the actual cost to interconnect the applicant, but that such differences may still occur. Thus, the Utilities stated that they crafted a proposal that ensures their legal right to cost recovery, using a currently established recording methodology, while still improving interconnection cost

predictability by offering price certainty to a subset of Rule 21 interconnection applicants. Specifically, the Utilities proposed truing up the difference, either due to overcollection or undercollection, in customer rates through the GRC process by treating the fixed price contracts for the Rule 21 interconnections consistent with existing practices for other applicant-requested distribution construction work. The Utilities explained that an estimate is developed for the work to be performed and payment is made prior to work commencing. After an estimate is provided, if the applicant wishes to proceed, the applicant pays that estimate. The work is then performed. If the estimated costs are equal to the recorded costs, this activity is recorded as net zero plant. For PG&E and SCE, if the estimated costs exceed the recorded costs, the balance is recorded as miscellaneous Other Operating Revenue. If the estimated costs are less than the recorded costs, the excess is net rate base recorded, which is booked to plant-in-service or rate base for recovery through customer rates. For SDG&E, any
over-collection or under-collection is recorded to rate base. In short, any cost over or under recovery is allocated to ratepayers.

The Utilities emphasized that their joint price certainty proposal is designed to minimize interconnection cost variances because eligibility for the fixed price option is limited to Interconnection Requests that do not have large impacts to the distribution system. Although the Utilities foresee that many Interconnection Requests will be eligible for the fixed price option, the eligible projects will be projects that do not require significant distribution upgrades and/or are not dependent upon facilities triggered by earlier-queued projects, which is designed to ensure a high level of confidence in the fixed price estimate, and thus minimize cost variances. The Utilities also point out that other proposed restrictions reduce the risk of cost variances such as: (1) the exclusion of certain cost elements, such as costs of required environmental studies, environmental mitigation, etc., due to the unpredictability and potential magnitude of these costs, and (2) a firm deadline for fixed cost estimate payment to ensure cost estimates do not become stale. In summary, the Utilities argued that impacts to customer rates, if any, would be minimal from the fixed cost option.

On May 22, 2015, the following parties filed comments to the Utilities' Joint Cost Certainty proposal and Supplement: BioEnergy Association of California/Placer County Air Pollution Control District, SolarCity, California Solar Energy Industries Association, NRG Energy, Inc., California Energy Storage Alliance, Clean Coalition, and the Interstate Renewable Energy Council. Generally, the commenting parties supported the concept of cost certainty reflected in the Utilities' proposal, but a number of parties also provided critiques regarding specific aspects of the Utilities' Fixed Price Option proposal:

- **Eligibility requirements**: Some parties argued that the eligibility requirements for the Fixed Price Option are overly constrained and apply to a limited scope of the simplest projects. In order to open the Fixed Price Option up to a greater number of projects, Clean Coalition and Interstate Renewable Energy Council call for the $500,000 upper limit on system upgrades to be dropped. One party also proposed dropping the No Substation Upgrades requirement for Fixed Price Option eligibility, as well as the 5 MW eligibility limit for Independent Study Review projects.

- **$10,000 fee**: Some developers opposed the $10,000 fee to elect the Fixed Price Option as excessive and lacking justification.

- **60 Business Day study period**: SolarCity contended that the 60 Business Day timeline for developing a fixed price estimate should be reduced to 20 Business Days, as this would be consistent with timelines to complete a Supplemental Review. Clean Coalition stated that the proposed 60 Business Day timeline for developing a fixed price estimate would significantly lengthen the Fast Track process and has not been properly justified by the Utilities, and instead suggested a 30 Business Day timeline.

- **Fixed Price Estimate Granularity and Review**: Interstate Renewable Energy Council proposed that the Fixed Price Option estimate includes a detailed breakdown of equipment costs, labor hours and rates, and all other components of the estimate, and also believes that the Fixed Price Option process should include the ability for the applicant to discuss the fixed price estimate with the Utility.

Some parties' comments included alternative proposals to increase cost certainty and predictability within the interconnection process, either alongside or in lieu of the Utilities' Fixed Price Option proposal. For instance, a number of parties expressed support for more up-front data on system upgrade component costs and local system configurations at a customer's site, which led to the Unit Cost Guide and Enhanced Pre-Application Report proposals put forth in the November 9, 2015 Joint Motion on Cost Certainty.

However, some parties sought a more expansive cost certainty model than the Utilities' Fixed Price Option proposal, referred to as a Cost Envelope, which they propose be available to more projects and have a wider band of applicant responsibility for variations between estimated and actual costs than the Fixed Price Option. BioEnergy Association of California/Placer County Air Pollution Control District suggested a hybrid cost certainty framework in which the Utilities' Fixed Price Option can exist alongside a Cost Envelope option that covers all other projects that are ineligible for the Fixed Price Option. BioEnergy Association of California/Placer County Air Pollution Control District proposed a cost envelope with a declining envelope range that narrows as a project progresses through the application stages: a 25% envelope after System Impact Study, or a 15% envelope after Facilities Study. Overestimations beyond the lower limit would be refunded to the applicant, whereas underestimations over the upper limit would be picked up by Utility shareholders. This would hold Utilities accountable for making accurate estimations and would encourage greater accuracy and predictability of interconnection costs.

Clean Coalition, on the other hand, proposed a 10 – 25% envelope for all projects that pass Fast Track or Independent Study Review — i.e., in lieu of the Utilities' Fixed Price Option — to be elected by applicant any time before entering into an Interconnection Agreement. Clean Coalition's proposal would maintain the No Substation Upgrade requirement as in the Fixed Price Option proposal, would allow 30 days for preparation of the estimate, and would allocate actual costs beyond the cost envelope limit to the Utilities' proposed GRC true-up mechanism. Clean Coalition suggests that an Independent Evaluator review balancing account entries to ensure cost estimates are accurate and consistent.

ORA, however, supported an alternative approach – "the Massachusetts model." As explained by ORA, under the Massachusetts cost envelope model, interconnection applicants pay cost overruns of up to ten percent over the estimated cost and utility shareholders absorb any overruns that exceed the ten percent Ratepayers do not assume any risk for cost overruns.[1]

[1] ORA also opposed the Clean Coalition's proposal for a modified Massachusetts Model which would similarly allocate cost overruns to ratepayers.

ORA reasoned that the Massachusetts cost envelope model serves to better protect ratepayers by keeping any interconnection cost overruns shared between the applicant (the entity creating the cost) and the Utility (the entity responsible for the cost estimate.) ORA contended that the Massachusetts cost envelope model also protects applicants from excessive increases in costs charged by the Utilities, while also providing an incentive for the Utilities to provide accurate cost estimates since the shareholders are responsible for any costs incurred above the 10% cap.

ORA argued that the Utilities improperly implied in their Supplement to the Joint Utilities' Cost Certainty Proposal that utilities are always guaranteed a rate of return on their investments. ORA contended that the Commission may authorize cost recovery for utilities if they show that the costs incurred are justified, and the Utilities' Cost Certainty Proposal with a "true-up" for the difference between actual and recovered costs in future GRCs is fundamentally flawed and presumptuous because it does not provide for Commission review.

ORA concluded that the Utilities' Cost Certainty Proposal improperly shifts a utility's revenue shortfall resulting from their inaccurate cost estimates to ratepayers, which, under the current ratemaking principles, is the responsibility of the generators, and the Utilities have provided no rationale to support the reasonableness of this proposed cost shift. ORA stated that the Commission's longstanding ratemaking principles include avoiding cross-subsidies between customer classes by ensuring that the entity that creates costs pay those costs. ORA recommended adopting the Massachusetts model for Cost Certainty of Interconnection and rejecting the Joint Utilities' Cost Certainty Proposal.

2. Pre-Application Report Enhancements and Unit Cost Guide

As set forth above, the moving parties explained that Electric Tariff Rule 21 would be improved with the development of: (1) a Unit Cost Guide to give generation developers a readily available price list of typical interconnection facilities and equipment, and (2) adding specific data, with associated costs and timing, to be included in the Enhanced Pre-Application report.

The goal of the Pre-Application Report and Unit Cost Guide is to make cost data available earlier to prospective interconnection applicants. The moving parties' proposal is captured in the Cost Guide Implementation Principles, reproduced in Attachment A, which provide for the Utilities to develop the Guide within 90 Calendar Days of the Commission's decision. Using a consistent format, each Utility will publish a Cost Guide for facilities generally required to interconnect generation to their respective Distribution systems. While not be binding for actual facility costs, the Cost Guide will provide the anticipated cost of procuring and installing delineated facilities during the current year, acknowledging that costs may vary among the Utilities and within an individual Utility's service territory. The Cost Guide will include forecast costs for five years to allow project planning.

The specific proposals for Enhancements to the Pre-Application Report are set forth in Attachment B. These enhanced and optional aspects will allow interconnection applicants to obtain a Report tailored to the specific needs of the project and the applicant.

We find that providing prospective interconnection applicants cost estimates at an earlier stage and in a readily available format will improve the operation of Electric Tariff Rule 21. We, therefore, conclude that the jointly requested and unopposed proposed revisions to Tariff Rule 21 as set out in

Attachments A and B should be approved. The Utilities should comply with the filing schedules as agreed-to in Attachments A and B.

3. Behind-the-Meter Storage

We similarly grant the joint request for improvements to the treatment of non-exporting, behind-the-meter storage pursuant to Rule 21. Those improvements include clarifications of the manner in which storage charging load will be addressed in evaluating requests to interconnect energy storage devices, with load aspects being dealt with pursuant to Electric Rules 2, 3, 15 and 16 just like other load. Cost allocation will also use the new load impacts as the determining factor, and a new Interconnection Process Guide detailing the processes by which the load aspects of energy storage are reviewed, including specific size thresholds and cost responsibility of load-related upgrades not already included in Rule 21 or Rules 2, 3, 15 and 16, will improve the process for interconnection of behind the meter storage.

We also approve and endorse the proposed process for continuing the collaborative efforts that have to date been so fruitful. The moving parties seek to continue discussions initiated during the workshops to consider additional potential changes to Rule 21. Specifically, the parties intend to work on defining criteria for an expedited interconnection process for non-exporting energy storage, for a particular AC/DC converter to immediately pass Rule 21 Fast Track Initial Review after successful compliance testing, and a filing date for a status report on developing consensus-based requirements to address the "inadvertent export" issue. We, therefore, conclude that the jointly requested and unopposed proposed revisions to Tariff Rule 21 as set out in Attachment C should be approved, and the on-going process proposed in Attachment C adopted as well. The Utilities should comply with the filing schedules as agreed to in Attachment C, and summarized in the Master Filing Schedule shown in Attachment D to today's decision.

4. Establishing a Cost Certainty Framework

Senate Bill (SB) 350 established a variety of new procurement standards, including an increase in renewable procurement to 50% by 2030 and additional penetration of electric vehicles and various greenhouse gas emissions reduction targets.[2] In addition, SB 1122 established a 250 megawatt (MW) bioenergy procurement target, bolstered by Governor Brown's October 30, 2015 Emergency Order on Forest Biomass.[3] These statutes and policies directly inform today's decision and our overall commitment to facilitating resource interconnection and grid integration of intermittent renewable generating resources.[4] We anticipate the need to expeditiously integrate more wind and solar resources, responding to the changes in system-wide customer load due to anticipated increase of customer rooftop solar and Electric Vehicles deployment: integration through interconnection. The role and functionality of distributed energy resources (DERs) on the distribution and transmission grid informs today's actions. DERs, such as electric vehicles and distributed storage, are tools we need harness to balance out the intermittency of wind and solar resources, and they can play that balancing role only if timely interconnected. DERs are a critical piece in meeting the grid integration challenge.

[2] Public Utilities Code Section 454.51 and Section 454.52.
[3] Governor Brown's Emergency Order: https://www.gov.ca.gov/docs/10.30.15_Tree_Mortality_State_of_Emergency.pdf.
[4] CPUC Staff Whitepaper. "Beyond 33% Renewables: Grid Integration Policy for a Low Carbon Future." November 25, 2015. http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/Beyond33PercentRenewables_GridIntegrationPolicy_Final.pdf.

D.12-09-018 established interconnection rules for developers and utilities in adopting Electric Tariff Rule 21 (Rule 21) which governs the process by which grid-interactive DER projects interconnect and integrate to the distribution grid. Rule 21 establishes the standards to enable new facilities to connect to the distribution grid while enabling utility engineers to interconnect new DER facilities safely and investor owned utilities to maintain overall the system safety and reliability critical to ratepayers, electric workers, and our economy.

To recover the costs of interconnection, our rules require DER developers to finance distribution grid capacity upgrades to accommodate the new two-way power flows on the distribution grid introduced by their generation. As part of the Rule 21 study process, the utility produces an electrical plan of service and an estimated cost to construct any identified system upgrades. Under the current framework, the project developer includes these estimated upgrade costs in the course of securing project financing to fund the project. Under our current rules, project developers assume unlimited liability for any cost overruns incurred,[5] even those stemming from circumstances unforeseen by the utility or by the developer, or which might have been predictable to the utility with additional data and grid analysis. These costs are either directly passed onto ratepayers via higher prices or would lead to a high failure rate of applicant DER projects. In either circumstance, this unlimited liability creates a large risk profile for distributed energy resource project development in California, raising the cost of investing in DER, and thus the cost to ratepayers for an eventual Power Purchase Agreement (PPA). One party cites instances of ten- and thirteen-fold variations in interconnection costs over the original estimate, and describes such degree of uncertainty "crippling for private developers and discouraging for public

[5] Rule 21 Section E.4.c, Interconnection Cost Responsibility - Timing of Cost Identification.

agencies that are working with the state to achieve its climate and clean energy goals."[6] Today's decision reduces cost uncertainty, diminishes risk for project development, and is calculated to spur investment needed to meet California's statutory GHG reduction and renewable procurement and integration goals. Providing cost certainty to developers, utilities, and ratepayers is also a part of the Commission's overall mandate to provide safe reliable service at just and reasonable rates.[7]

Cost certainty is a framework that clearly communicates the precise level of financial risk assumed when funding capacity upgrades for distributed energy resource projects. As early as September 26, 2012 Amended Scoping Memo and Ruling in this proceeding, the Commission asked parties to propose ways to address barriers to the interconnection process, including the implementation of a cost certainty framework.[8] Over the course of the proceeding, parties have focused discussions around two proposed frameworks: a Fixed Price Option as proposed by the Joint Utilities, and a Cost Envelope, described in various permutations by IREC, Clean Coalition, ORA, and BioEnergy/PCAPCD.[9] The cost envelope was also recommended, in part, in the July 18, 2014 Energy Division Staff Proposal.[10] Both proposals intend to achieve greater cost certainty in the interconnection process. These two proposals are described in additional detail, below.

[6] Bioenergy/PCAPCD *Comments on the Joint Utilities' Motion for Interconnection Cost Certainty*, May 22, 2015, p. 5.

[7] Public Utilities Code Section 451

[8] Amended Scoping Memo and Ruling, September 26, 2012.

[9] *See,* Comments filed by Interstate Renewable Energy Council Inc., October 25, 2012, pg 7.

[10] CPUC Staff Proposal. "Cost Certainty for the Interconnection Process." July 18, 2014. *Found in,* Administrative Law Judge Ruling Setting Schedule for Comments on Staff Reports and Scheduling Prehearing Conference, Sept 29, 2014.

A successful cost certainty framework limits developer liability for inaccurate cost estimates provided by the utility to a reasonable level. Cost certainty shifts the balance between timeliness of creating the cost estimate and the accuracy of the estimate. The two primary Rule 21 study processes, Fast Track and Independent Study, balance these competing goals. We adopt a cost certainty framework, in part, to establish higher-confidence cost estimates and to reduce the impact of inaccurate cost estimates on project financing costs, with the express hope that ratepayers will benefit from reduced Power Purchase Agreement prices.

The crux of the debate between the two cost certainty frameworks center on two main questions: (1) does the proposed regime provide an adequate level of cost certainty to Rule 21 project developers, and (2) does the ratemaking treatment for actual cost incurred beyond the adopted limit of a developer's financial responsibility adequately align with the interests of ratepayers, developers, and utility shareholders.

In adopting a cost certainty framework, the Commission recognizes the challenges that utilities face in producing timely high-confidence cost estimates. These challenges include the need to produce interconnection studies in a timely manner while lacking adequate data on field conditions. We also recognize that, as a product of D.12-09-018, the Fast Track and Independent Study Process are relatively new, and that the utilities' execution of these processes will continue to evolve and improve as the utilities gain more experience processing applications for various types of Rule 21 projects.

We further anticipate that the Integration Capacity Analysis (ICA) being developed in the Distribution Resources Plan (DRP) proceeding (R.14-08-013) will help direct developers to grid locations with adequate hosting capacity (and thus a lower chance of triggering significant distribution system upgrades). Cost uncertainty is also reduced through the adoption of the Unit Cost Guide and Enhanced Pre-Application Report in today's decision because they will make system upgrades and associated costs more predictable.

We are also motivated by the need to encourage increasing the access, resolution, and representativeness of data utilized by the utilities in the interconnection process. Modernizing the interconnection process is the essential component ~~of our broader goals to develop a modern, "plug and play" grid~~to achieve our policy and statuary goals of interconnecting renewable energy, deploying distributed energy resource and reducing greenhouse gas emissions. In adopting a cost certainty framework, we aim to encourage and incentivize the utilities to take the necessary steps that will allow them to use the highest-resolution, most up-to-date asset management databases in performing interconnection studies. Increased access and use of higher-quality, timely data will improve the accuracy of cost estimates.

Under the Fixed Price Option, utilities would provide developers with a binding cost estimate in exchange for more up-front study time. As proposed, the Fixed Price Option would be available to distributed energy resource projects that meet the specific eligibility requirements, pay a $10,000 fee, and allow for a 60-businsess day up-front study period. The Fixed Price Option would then allocate the difference between estimated and actual costs to ratepayers. The utilities would put into rate base the capital expenditures associated with any system upgrades beyond the estimated cost funds provided by the developer, as the utilities would be funding the system upgrade costs themselves. If the fixed price estimate was too high, any unspent funds would be recorded as Other

Operating Revenue.[11] This revenue would presumably offset revenue requirement collections from ratepayers.

Critics of the Joint Utilities' Fixed Price Option anticipate that the eligibility requirements will prevent the projects that are in most need of cost certainty—i.e., projects applying to interconnect in the grid locations for which cost estimates are the most unpredictable—from accessing the Fixed Price Option and a cost certainty regime.[12] Other pre-requisites would deter many otherwise-eligible developers from electing it.[13] ORA argues that the Fixed Price Option improperly transfers the risk of inaccurate cost estimates from developers to ratepayers.[14] Other parties believe that transferring the risk of cost overruns from developers to utility shareholders would better align the incentivizes for the utilities to improve cost estimate accuracy.[15]

Under the Cost Envelope, a developer's responsibility for inaccurate cost estimates would be capped at a given percent of the provided interconnection cost estimate. The Cost Envelope framework would limit developer risk for inaccurate utility cost estimates to a given percent rage around the cost estimate provided by the utilities to the developer on the Generator Interconnection Agreement (GIA) signed by both parties. The cost envelope framework, as

[11] Joint Utility *Supplement to the Joint Utility Motion Proposing Rule 21 Tariff Language Implementing Joint Cost Certainty Proposal*, May 22, 2015, pp. 5-6.

[12] E.g., Bioenergy/PCAPCD *Comments on the Joint Utilities' Motion for Interconnection Cost Certainty*, May 22, 2015, p. 7.

[13] E.g., Clean Coalition *Comments on Joint Utility Motion on Language Implementing Joint Cost Certainty Proposal,* May 22, 2015, p. 2.

[14] ORA *Reply Comments on the Joint Utility Motion Proposing Rule 21 Tariff Language Implementing Joint Cost Certainty Proposal, June 8, 2015*, p. 8.

[15] E.g., ORA *Reply Comments*, June 8, 2015, p. 5; IREC *Comments on the Staff Reports Regarding Interconnection Cost Certainty and Energy Storage Interconnection*, September 12, 2014, p. 4; Bioenergy/PCAPCD *Comments on the Joint Utilities' Motion*, May 22, 2015, p. 10.

proposed, could be applied to all Rule 21 projects.[16] The Cost Envelope framework pushes the utility towards providing developers an accurate cost estimate while allowing the utility a reasonable buffer to absorb unanticipated overages.

The Joint Utilities argue that across-the-board DER interconnection cost certainty is premature given the unpredictable nature of studying larger, more complex projects in older and/or constrained grid locations. The utilities also argue that they lack experience interconnecting Rule 21 export projects.[17][18]

Parties such as IREC, Clean Coalition, ORA, and BioEnergy/PCAPCD assert that making utility shareholders responsible for cost overruns beyond the percent cap would squarely place the risk of inaccurate cost estimates on the utility. [19] This would be appropriate, parties reason, as utilities are the entities that are solely responsible for developing the estimates. The Joint Utilities counter by stating such a proposal violates cost-of-service ratemaking tenets, contradicts the Public Utilities Regulatory Policy Act of 1978 (PURPA), lacks detailed analysis, and unfairly shifts substantial risk to the utility without regard for critical inherent uncertainties in the interconnection review process and Rule 21's

[16] E.g., IREC *Comments on the Staff Reports Regarding Interconnection Cost Certainty and Energy Storage Interconnection*, September 12, 2014, p. 4.

[17] Rule 21 Non-Export projects are unlikely to trigger system upgrades and thus are not germane to the cost certainty discussion.

[18] . This lack of experience, according to the utilities, combined with the fact that data on estimated versus actual costs for post-D.12-09-018 Rule 21 export projects are not included in the proceeding record renders any adopted cost envelope range arbitrary and unsupported by evidence. The Joint Utilities, however, submit quarterly interconnection data reports to the CPUC's Energy Division containing confidential data on estimated costs, actual costs, and true-up.

[19] ORA *Reply Comments on the Joint Utility Motion Proposing Rule 21 Tariff Language Implementing Joint Cost Certainty Proposal*, June 8, 2015, p. 8.

compromise between the level of estimate certainty and interconnection process efficiency.[20]

For reasons detailed below, we elect to adopt a 25% Cost Envelope as a five year pilot as a cost certainty framework for all interconnection under Rule 21 under certain provisions as detailed in this decision.

4.1. Adoption of 25% Cost Envelope

Based on our review of the record, we conclude that the current Rule 21 interconnection process is not yielding sufficient ratepayer benefit and needs to be adjusted to create more cost certainty to achieve the state's statutory renewable procurement integration, and GHG reduction goals.

We acknowledge that a cost certainty framework is a new and innovative adjustment enabling more efficient integration of distributed energy resources. We anticipate that it will take some time to evaluate whether or not ratepayers are receiving adequate benefits from the framework. In consideration of the above, we adopt a cost envelope framework on a five-year pilot basis to test the model. The range of the cost envelope should be set at 25% (both above and below the utility provided estimate), per Clean Coalition,[21] and available to all projects applying for interconnection under the Fast Track or Independent Study Processes in Electric Tariff Rule 21, per IREC.[22] The pilot we authorize today is available to projects applying to the Fast Track and Independent Study Processes; the Utilities may file an advice letter to extend the Cost Envelope to projects in

[20] Joint Utility *Comments on the Staff Report Regarding Cost Certainty for the Rule 21 Interconnection Process*, September 12, 2014, p. 18.

[21] Clean Coalition *Opening Comments on Staff Proposals for Cost Certainty*, September 12, 2014, Attachment 3; Clean Coalition *Comments on Joint Utility Motion on Language Implementing Joint Cost Certainty Proposal*, May 22, 2015, p. 10.

[22] IREC *Comments on the Staff Report Regarding Interconnection Cost Certainty*, September 12, 2014, p. 4.

the Distribution Group Study Process[23] or Cluster Study. The Cost Envelope shall be applied to the estimated cost provided by the utility on the Generator Interconnection Agreement (GIA) documentation ~~for~~. In order to inform the GIA and to elect the Cost Envelope, projects that ~~elect and~~ successfully complete ~~both the initial and secondary phases of a given Rule 21 study process. For instance, a developer applying under the Fast Track Study Process must pay for and complete Initial Review and Supplemental Review; developers~~either Fast Track Initial Review or Supplemental Review must pay a new $2,500 deposit and allow an additional 20 business days for the Utility to develop a cost estimate following the completion of the engineering review phase.[24] Developers applying under the Independent Study Process must pay the required deposits and complete both a System Impact Study and Facilities Study in order to elect the Cost Envelope. These processes were established in D.12-09-~~018; the only modification we make to them today is applying the cost certainty framework to both of them a 5-year pilot.~~018. This cost envelope framework appropriately balances study timeliness and estimate accuracy by ~~requiring~~providing the Utilities additional up-front study time and financial resources to produce high-confidence cost estimates for Fast Track projects, and by requiring Independent Study Process projects to undergo the maximum available course of study, while ~~reducing unbound~~limiting developer liability to 25% above estimated interconnection costs. The cost envelope framework is designed to balance risk factors between developers, utility shareholders, and ratepayers.

[23] We note that the distribution group study process may be the appropriate process to interconnect microgrids; we direct Energy Division to monitor microgrid development and to determine if applying the cost envelope to the distribution group study process will facilitate microgrid deployment.

[24] To clarify, projects that pass either Fast Track Initial or Supplemental review must pay the $2500 deposit for a supplemental 20 business day cost envelope estimate development process within 10 business days of receiving the utility's non-binding cost estimate following completion of Initial or Supplemental Review

The Cost Envelope framework will work to better facilitate the interconnection of distribution energy resources and limit developer risk exposure for cost estimate overruns. Capping developer responsibility for inaccurate cost estimates, however, does not adequately address many of the root causes of these inaccuracies. According to the Joint Utilities, a primary source of cost estimate inaccuracy is the fact that a majority of field verification tasks—including environmental studies, biological studies, easement/rights checks, wind loading for poles, engineering and design, and "job walks"—as well as final detailed engineering are not currently performed until after completion of the Fast Track or Independent Study processes and the execution of a GIA.[~~23~~25] The Joint Utilities explain that while the decision to delay field verifications and detailed engineering until after the GIA adds a level of uncertainty to the study phase's cost estimate, it permits faster, more efficient processing of an applicant's interconnection request and conserves the resources necessary to perform such tasks until an applicant reaches a high level of confidence that it wishes to pursue interconnection.[~~24~~26]

We conclude that we need to improve the interconnection study process to make it more likely to yield an accurate cost estimate at the execution of the GIA. In adopting the 25% Cost Envelope, we establish new data collection requirements to track overestimates and underestimates to determine the effectiveness of this new cost envelope framework, as well as reporting metrics that will help the Commission and parties gauge the utilities' progress in modernizing the interconnection study process and producing high-confidence cost estimates. We also require more up-front work by the developer and the

[~~23~~25] Joint Utilities' *Response to Energy Division Staff Proposal on Cost Certainty*, September 12, 2014, pp. 13-14.

[~~24~~26] *Ibid*, p. 10.

utility, as described below, in order to access this cost certainty framework. Overall, our pilot adds steps to the work that must be completed by the developer and the utility to reduce the margin of cost estimate uncertainty.

The five-year pilot we adopt in this decision includes a requirement that developers shall submit a more thorough and detailed Rule 21 interconnection application in order to elect the Cost Envelope framework. We take from the Joint Utilities' Fixed Price Option proposal the "Technical Scope Package," as it would provide the utility with additional details on the applicant generator as it performs its study and derives its cost estimates.~~[25]~~[27] As part of this requirement, the developer in electing the cost envelope for interconnection shall provide the following "Technical Scope Package" as part of its interconnection application:[28]

1. Final location of the Point of Common Coupling (Point of Change of Ownership);
2. Final location of the Point of Interconnection;
3. Confirmation of service voltage;
4. Confirmation that technical data provided in the Interconnection Request is accurate, including equipment type, model and manufacturer;
5. A site drawing of a scale of 1:30 or less, which shows the final location of the Point of Common Coupling, Point of Interconnection, and final location and routing of conductors and equipment between the Point of Common Coupling and the Point of Interconnection; and
6. Identification of any constraints or limitations related to the siting or routing of conductors and equipment between the Point of Common Coupling and the Point of Interconnection.

The Cost Envelope will be enacted upon the cost estimate provided to the developer in the Generator Interconnection Agreement documentation (GIA). In signing a GIA, the utility and developer agree that the Cost Envelope shall be

~~[25]~~[27] Joint Utility *Motion Proposing Rule 21 Tariff Language Implementing Joint Cost Certainty Proposal*, April 1, 2015, pp. 5-6.

[28] The utility will evaluate any modifications to determine if such modifications constitute a Material Modification to the Interconnection Request, consistent with Rule 21 Sections C and F.3.b.v.

applied to the actual cost of facilities and system upgrades upon final accounting true-up, following the utility's issuance of Permission to Operate. Estimated and actual cost documentation provided to a developer shall be itemized, such that a developer and the Commission can understand the exact breakdown of labor, Operations and Maintenance, and capital expenditures for each job activity and installed piece of equipment. Upon final accounting true-up, the utility shall provide documentation to the developer and the Commission stating itemized actual costs.

We clarify that the Cost Envelope shall only apply to the interconnection costs that are under the utilities' control and should be thus reasonably expected to be estimated within 25% accuracy. For instance, the Joint Utilities' Fixed Cost Option proposal would exclude costs associated with required environmental studies, environmental mitigation, permits, or easements related to the construction and installation of interconnection facilities or distribution system upgrades.[~~26~~29] These cost elements are incurred in response to a developer's interconnection request and do not directly pertain to upgrades to a utility's distribution system. As such, these costs shall remain the sole responsibility of the project developer.

We further order the creation of a memorandum account to track actual interconnection costs that fall above or below the 25% envelope.[~~27~~30] Each entry into the memorandum account shall utilize standardized line-item accounting and shall include itemized actual and estimated costs broken down into relevant categories of component costs, labor, and Operations and Maintenance, a

[~~26~~29] Joint Utilities *Cost Certainty Proposal*, January 18, 2013, p 6; Joint Utilities *Motion Proposing Rule 21 Tariff Language Implementing Joint Cost Certainty Proposal*, April 1, 2015, p 7.

[~~27~~30] Clean Coalition *Opening Comments on Staff Proposals for Cost Certainty*, September 12, 2014, Attachment 3; Joint Utility *Comments on Proposed Decision Granting Joint Motions to Approve Proposed Revisions to Electric Tariff Rule 21*, March 7, 2016, p. 6.

description of the main driver(s) of the inaccurate estimate, and an explanation of how the utility attempted to mitigate or take steps to prevent estimates outside of the 25% range. The net of both cost and proceeds incurred should be reflected in the account balance. The utilities shall file a Tier 2 advice letter adopting the cost envelope and associated memorandum accounts within 60 days of today's decision. At minimum, the advice letter should include interconnection application documentation including cost envelope selection box and "technical scope package," and memorandum account details, including explanation about each project expense, how project expenses will be tracked over time and how booked expenses will be netted across projects. The utilities shall also provide a technical report, which includes comprehensive and detailed information about each entry into the memorandum account, attached as an appendix.

Each utility would then be able to request recovery of the account balance in a separate section of its triennial General Rate Case, subject to reasonableness review. Utilities may be able to recover from ratepayers the net of inaccurate estimates upon a showing that such costs were prudently incurred, given the causes of cost estimate inaccuracy within a utility's ability to control. Net cost overruns deemed imprudently incurred would be allocated to utility shareholders.

In our determination, the memorandum account equitably spreads the risk of inaccurate cost estimates between developers and utility shareholders across the entire portfolio of Rule 21 projects. The Commission deems that the potential shareholder responsibility for imprudently incurred interconnection costs through a reasonableness review properly aligns the impetus for better cost estimating by the entity that is solely responsible for developing the estimate: the utility. Understandably, records submitted that do not use a traditional line item accounting format will be more challenging to review. Using line-item accounting, interconnection cost overruns will be knowable and sharable. This type of accounting methodology used to describe cost driver information will assist the reasonably knowledgeable accountant. Component pieces, labor, expenses for upgrading different elements of the grid, all of these numbers are knowable, countable, recordable, and sharable. Any submission of cost overruns should identify where costs accrued, when, and how the utility attempted to mitigate the situation.

4.2. Imposing Potential Shareholder Liability for Inaccurate Cost Estimates is Permissible

The Joint Utilities comments regarding the Staff Report,~~[28]~~[31] claiming that the Staff Proposal's Cost Envelope Model "appears to violate PURPA, in that it denies the IOUs of the recovery of interconnection costs."~~[29]~~[32] The Joint Utilities imply that unforeseeable complications may arise after its estimate of interconnection cost, and thus a utility may be reasonably required to spend in excess of the cost envelope margin beyond its binding estimate to safely and reliably interconnect the facility to the distribution grid. We disagree.

The cost envelope process described herein does not violate PURPA because it allows the utility to recover costs that exceed the 125% cost estimate that would be presumed reasonable. Specifically, the utility could seek to show in its next General Rate Case (GRC), or in another appropriate proceeding. The utility can determine if the cost overruns themselves were reasonable, and if the Commission finds that those costs were reasonably incurred then the utility may

~~[28]~~[31] *Comments of Southern California Edison Company (U 338-E), San Diego Gas & Electric Company(U 902-E) and Pacific Gas and Electric Company (U 39-E) on The Staff Report Regarding Cost Certainty For The Rule 21 Interconnection Process* (Joint Utilities' Comments), filed on September 12, 2014 in R. 11-09-011.

~~[29]~~[32] Joint Utilities' Comments at p. 22.

recover costs exceeding the 125% envelope from ratepayers. If the utility either decides not to seek compensation for excess costs or the Commission fails to find such costs to be reasonable, then such overages will accrue to the utility's shareholders.

Qualifying Facilities, as defined by PURPA, may apply for interconnection under Rule 21. PURPA defines the interconnection costs that a utility may recover from Qualifying Facilities in 18 Code of Federal Regulations Section 292.306 (emphasis added):

> "Interconnection costs means the *reasonable* costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility . . .."

The Joint Utilities acknowledge:

> "[Section 292.306] is designed to provide the State regulatory authorities . . . with the flexibility to ensure that all costs which are shown to be reasonably incurred by the electric utility as a result of interconnection with the qualifying facility will be considered as part of the obligation of the qualifying facility under it."[~~30~~][33]

The reasonableness review appropriately balances risk between developers, shareholders, and ratepayers. While the utilities assert that PURPA creates a barrier, we disagree because we give the utilities the opportunity to demonstrate reasonableness.

[~~30~~][33] Joint Utilities Comments at p. 22, citing 1977-1981 Regulations Preambles ¶ 30,128,866 (1980) (emphasis added).

4.3. Utilities must update their interconnection process data usage capabilities

The aforementioned procurement mandates, and the anticipated proliferation of distributed energy resources generally, point to a fundamental need for better data and back-end IT systems at the disposal of the utility engineers who perform interconnection studies. In adopting the memorandum account, we stress that we view the opportunities afforded by the current Rule 21 study processes as a floor and not a ceiling. The utilities should perform the necessary in-house and field studies that can produce an estimate within a 25% range of actual interconnection costs.

The utilities' current cost estimating process relies on a desk review of the applicant generator's impact on the local distribution system, without the benefit of detailed power flow modeling, field verification, or final detailed engineering. Cost estimate inaccuracy can be attributed to a utility's inability to predict actual conditions in the field for the utility's distribution system or the site itself. This lack of accuracy results in part from the project information provided in a developer's application and the system data the utility utilizes to complete an interconnection study. The future interconnection process should be able to inform developers about dispatch priority concerns, conflicting real-time grid needs,[~~31~~34] and other real-time distribution grid signals to facilitate the timely interconnection of various types of DER facilities with bidirectional capabilities.[~~32~~35] We invite the utilities to submit applications, as necessary, to ensure that they have the tools required to produce the accurate cost estimates required for this process. The applications should be well-calibrated to produce a

[~~31~~34] Administrative Law Judge's Ruling 14-10-003. Noticing Workshop Jointly Led by the California Independent System Operator, March 24, 2016, p. 5.

[~~32~~35] D. 16-01-025. Decision Regarding Underlying Vehicle Grid Integration Application and Motion to Adopt Settlement Agreement, January 14, 2016, p. 150.

higher degree of cost certainty, achieve the renewable procurement and integration goals the legislature has mandated, and are well-designed to maintain system safety, reliability, and just and reasonable rates.

Utility distribution engineers should utilize their creativity, talents and expertise, to analyze distribution grid data provided through multiple gateways in developing interconnection upgrade cost estimates. For projects electing the Cost Envelope, the final cost estimate, provided in the GIA will attach after two study processes. These study processes should adequately allow the utility to estimate interconnection costs within 25% accuracy when interconnection and integrating a new DER facility to the distribution grid in a safe and reliable manner at just and reasonable rates.

4.4. Cost Envelope Pilot and Required Reporting

The discussion above outlines our expectations for appropriately balancing risk between the developer, utility shareholders and ratepayers to facilitate timely and accurate interconnection cost estimates to enable the integration of more DERs to the distribution grid. In light of the data that we will gather (as described above) and as additional experience is gained using the Cost Envelope framework, we recognize that the framework will need to be revisited as the utilities and developers gain experience. Therefore, we treat the Cost Envelope framework that we adopt in this decision as a five year pilot period. A five-year pilot period is an appropriate length of time to allow the utilities to collect a representative sample of projects from which to evaluate the effectiveness of the 25% Cost Envelope to interconnect and integrate DER into the distribution grid. Given that the interconnection process can take over two years to complete for certain projects, the pilot period will allow the Commission, in conjunction with utilities and other stakeholders, to inform a permanent cost certainty framework based on empirical cost estimating data and the improvements to the utilities' data access and utilization we order in this decision. We direct the utilities, in consultation with the Commission's Energy Division, to host a series of workshops, at least semi-annually, to provide a forum for parties and the Commission to ~~inquire about~~discuss the cost envelope pilot and the utilities' progress in improving the interconnection process~~ progress and to provide guidance. ~~.

To help evaluate the pilot period, the utilities shall continue to submit, on a quarterly basis, all pending and completed Rule 21 interconnection project true-up documents to the Commission. In the quarterly report, we further direct the utilities to use consistent measurements, to produce records and to develop tools to track the progress by which the utilities increase the accuracy of their cost estimates in the interconnection process. At minimum, the utilities shall include in this report metrics that indicate progress towards realizing improved data access and utilization in the course of modernizing the interconnection process and producing higher confidence cost estimates. These metrics will help us evaluate the pilot period~~ and our ultimate objective of creating a "plug-and-play" distribution grid~~. The quarterly reports shall also track actual costs of preparing a cost envelope estimate for Fast Track applicants as well as cost differential data and narrative technical descriptions of all entries into the memorandum account. The utilities shall host a workshop with parties to discuss the format of the new sections of the quarterly report within 120 days of today's decision. In consultation with Energy Division, the utilities shall also establish a working group to refine these metrics and reporting, with the objective of improving the interconnection process to create ~~a "plug-and-play"~~an agile distribution grid.

The utilities shall continue to provide both the public and private Rule 21 Quarterly Report to ensure that utilities continue to develop robust tracking and metrics of success to submit to Energy Division for further analysis. The Quarterly Report shall be broken down by facility type for greater analysis capacity.[~~33~~36] Any further reporting or metrics requests by Energy Division shall be added to the Rule 21 Quarterly Report.

We adopt the cost envelope and associated new processes as a five-year pilot because such changes do not provide for an "apples to apples" comparison to past interconnection projects, and thus the cost envelope need not be limited to cost overruns or underestimates as indicated by the average or range of past projects. We intend to evaluate the efficacy of the interconnection process, including the deviations between estimated cost and actual cost, under the cost envelope framework pilot. The process we pilot is calibrated to reduce uncertainty, and yield more information that will incentivize and reduce the cost for renewable development, and for the ratepayers who pay Power Purchase Agreement prices. We note that this five-year pilot period will also see an overall increase in customer energy choices, bolstered by the rollout of time-of-use pricing. We acknowledge that a reduction in risk and uncertainty in the deployment and integration of distributed energy resources will facilitate expanded customer choice. At the end of the pilot, the utilities may file an application to make the cost envelope pilot permanent if the pilot successfully enables distributed energy resources to interconnect to the grid. The Commission will need to consider at the conclusion of this pilot how the Cost Envelope

[~~33~~36] Reporting should differentiate applications for storage facilities, electric vehicle projects, solar, wind, bioenergy and other types of projects, including combined DER project facilities, so that Energy Division can determine where more guidance is required.

framework has impacted both Power Purchase Agreements and the accessibility of customer choice.

5. Smart Inverted Working Group – Continued Collaboration

Early in the nearly five-year time this proceeding has been open, the parties created the Smart Inverter Working Group (SIWG) as a forum for collaboratively developing advanced inverter functionality for inclusion in Rule 21. The productive history, current work, and a compliance filing requirement for the Working Group is detailed in Attachment E. We encourage the parties and other interested stakeholders to continue to participate in the Working Group. Our Staff in the Energy Division will also continue to monitor emerging issues as improved inverters are deployed and communication protocols developed.

Consensus proposals pertaining to Smart Inverter Working Group recommendations or Rule 21 interconnection more broadly may be brought forward for Commission consideration by the Utilities in the form of Advice Letters or Applications as appropriate. Other parties may file Petitions for Rulemaking pursuant to Rule 6.3 of the Commission's Rules of Practice and Procedure or Complaints as set forth in Rule 4. The Commission has opened two proceedings related to distributed resources where interconnection issues may also be addressed: Rulemakings (R.) 14-08-013 and R.14-10-003.

6. Comments on Alternate Proposed Decision

The alternate proposed decision of Commissioner Catherine J.K. Sandoval in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on ~~_______________, and~~May 26, 2016 by Fronius USA, California Solar Energy

Industries Association, Bioenergy Association of California, Clean Coalition, Interstate Renewable Energy Council, Solar City, ORA, and jointly by SCE, PG&E and SDG&E. Reply Comments were filed on ~~_____________, by _____________.~~May 31. 2016 by ORA, SolarCity, IREC, Clean Coalition and SCE, PG&E and SDG&E jointly.

In response to comments, we make several minor clarifications. We summarize these changes. We clarify that the Cost Envelope pilot does not apply to the Distribution Group Study Process or the Cluster Study process; however, the utilities may file an advice letter at a later date to expand the pilot to these processes once there is sufficient data available. We clarify how the pilot applies to the Fast Track study process. In response to comments from ORA, we clarify the information required for the memorandum accounts being piloted. In response to the joint comments from the Utilities, we extend the timeline for the filing of the initial tariff to 60 days. Other minor clarifications are made throughout the decision.

7. Assignment of Proceeding

Michael Picker is the assigned Commissioner and Maribeth A. Bushey is the assigned ALJ in this proceeding.

Findings of Facts

1. On November 9, 2015, SCE, SDG&E, PG&E, California Solar Energy Industries Association, Clean Coalition, CODA Energy and Interstate Renewable Energy Council, Inc., filed and served their joint motion proposing Pre-Application Report Enhancements and the development of a Unit Cost Guide.

2. The specific elements of the Unit Cost Guide are set forth in Attachment A to today's decision.

3. The specific elements of the Pre-Application Report Enhancements are set forth in Attachment B to today's decision.

4. No party opposed the proposed Pre-Application Report Enhancements and development of a Unit Cost Guide.

5. The proposed Pre-Application Report Enhancements and development of a Unit Cost Guide are reasonable.

6. On November 18, 2015, PG&E, SCE, SDG&E, the Interstate Renewable Energy Council, Inc., the Clean Coalition, Robert Bosch LLC and Stem, Inc. filed and served a joint motion setting forth proposed revisions to Electric Tariff Rule 21 to address interconnection of behind-the-meter, non-exporting energy storage. The specific actions to be taken and the applicable timetable for behind-the-meter, non-exporting energy storage are set forth Attachment C to today's decision.

7. No party opposed the proposed revisions to Electric Tariff Rule 21 to address interconnection of behind-the-meter, non-exporting energy storage.

8. The proposed revisions to Electric Tariff Rule 21 to address interconnection of behind-the-meter, non-exporting energy storage are reasonable.

9. Distributed energy resources, such as electric vehicles and distributed energy storage, are tools for balancing out intermittency of interconnected wind and solar resources. Electric Tariff Rule 21 generally governs the interconnection process for distribution energy resources.

10. A cost certainty framework establishes a higher-confidence cost estimate and reduces the impact of inaccurate cost estimates on financing costs for distribution energy resource projects. It is reasonable to assume that ratepayers should benefit from reduced Power Purchase Agreement prices from a cost certainty framework.

11. The cost envelope framework with the process improvements adopted herein appropriately balances risk factors between developers, utility shareholders and ratepayers. This cost envelope framework appropriately balances study timeliness and estimate accuracy by requiring projects to undergo the maximum available course of study while reducing unbound developer liability.

12. It is reasonable that the cost envelope framework be set at 25%.

13. It is reasonable to create a memorandum account for the cost envelope framework accounting~~.~~ with a technical report attached as an appendix within 60 days.

14. It is reasonable to utilize the cost envelope framework on a ~~5~~five year pilot basis.

15. It is reasonable to require the utilities to provide robust reporting and metrics to enable the Commission to monitor progress in developing an interconnection process that supports ~~a "plug-and-play"~~an agile distribution grid. Increased access and use of higher-quality, timely data will improve the accuracy of cost estimates.

16. New data collection requirements are needed to reduce the margin of cost estimate uncertainty.

17. It is reasonable for the utilities to require the developers to include a technical scope package in their generator interconnection application if they elect the cost envelope framework.

18. It is reasonable for the utilities to create memorandum accounts to track all interconnection costs that exceed the 25% cost envelope.

19. It is reasonable for the utilities to host semi-annual workshops about the changing interconnection process and receive input from parties and the Commission.

20. The Smart Inverter Working Group has completed its technical recommendations for Phase 2 communication protocols and Phase 3 additional advanced inverter functions after three years of collaboration and consensus-building.

21. It is reasonable for the utilities to revise Rule 21 to reflect the technical requirements of the Smart Inverter Working Group's recommendations for Phase 2 communication protocols and Phase 3 additional advanced inverter functions, following additional discussions to refine areas that require further consensus.

Conclusions of Law

1. The November 9, 2015, Joint Motion of SCE, SDG&E, PG&E, California Solar Energy Industries Association, Clean Coalition, CODA Energy and Interstate Renewable Energy Council, Inc., should be granted consistent with today's decision.

2. The November 18, 2015, joint motion of PG&E, SCE, SDG&E, the Interstate Renewable Energy Council, Inc., the Clean Coalition, Robert Bosch LLC and Stem, Inc. setting forth proposed revisions to Electric Tariff Rule 21 to address interconnection of behind-the-meter, non-exporting energy storage, with specific actions and applicable timetable for behind-the-meter, non-exporting energy storage are set forth Attachment C to today's decision, should be granted.

3. Senate Bill (SB) 350 (de León, Chapter 547, 2015) requires the Commission to focus energy procurement decisions on reducing greenhouse gas (GHG) emissions by 40 percent by 2030, including efforts to achieve at least 50 percent

renewable energy procurement, doubling of energy efficiency, and promoting transportation electrification. Public Utilities Code 451.51 and 451.52.

4. Decision 12-09-018 establishes interconnection rules for developers and utilities in adopting Electric Tariff Rule 21 (Rule 21). Rule 21 should be updated to apply a cost envelope of 25% for interconnection processes. This cost envelope should apply for a provisional five -year term.

5. The cost envelope should be applied to the estimated cost provided by the utility on the Generator Interconnection Agreement (GIA) documentation ~~for~~. In order to inform the GIA and to elect the Cost Envelope, projects that ~~elect and successfully complete both the initial and secondary phases of a given Rule 21 study process~~successfully complete either Fast Track Initial Review or Supplemental Review must pay a new $2,500 deposit and allow an additional 20 business days for the Utility to develop a cost estimate following the completion of the engineering review phase. Developers applying under the Independent Study Process must pay the required deposits and complete both a System Impact Study and Facilities Study in order to elect the Cost Envelope.

6. The utilities should continue to provide both the public and private Rule 21 Quarterly Report to ensure that utilities continue to develop robust tracking and metrics of success to submit to Energy Division for further analysis. The Quarterly Report shall be broken down by facility type for greater analysis capacity. Any further reporting or metrics requests by Energy Division shall be added to the Rule 21 Quarterly Report.

7. The utilities should host workshops, in consultation with Energy Division, at least semi-annually, to provide a forum to inquire about the utilities interconnection process progress and to provide guidance.

8. The utilities should create a memorandum account to track interconnection costs that are either above or below the 25% cost envelope for reasonableness review for recovery in either a general rate case or in a subsequent application. The memorandum account should include a description of the main driver(s) of the inaccurate estimate, and an explanation of how the utility attempted to mitigate or take steps to prevent estimates outside of the 25% range.

9. Code 18 of Federal Regulations Section 292.306 enables Qualifying Facilities to interconnection to the grid and allows the utility to recover those interconnection costs that are reasonable.

10. The utilities may seek to recover from ratepayers the actual interconnection costs that exceed the cost envelope framework upon a showing of reasonableness. This reasonableness review may occur in the utility's general rate cate or in a standalone application.

11. The parties should be encouraged to continue their now well-established collaborative process to raise and resolve interconnection issues.

12. This proceeding should be closed.

13. This decision should be effective immediately.

O R D E R

Therefore, **IT IS ORDERED THAT**:

1. The November 9, 2015, Joint Motion of Southern California Edison Company, San Diego Gas & Electric Company, Pacific Gas and Electric Company, California Solar Energy Industries Association, Clean Coalition, CODA Energy and Interstate Renewable Energy Council, Inc. setting forth proposals for the development of a Unit Cost Guide, as further specified in

Attachment A, and Pre-Application Report Enhancements, as shown in Attachment B, is granted consistent with today's decision.

2. The November 18, 2015 joint motion of Southern California Edison Company, San Diego Gas & Electric Company, Pacific Gas and Electric Company, the Interstate Renewable Energy Council, Inc., the Clean Coalition, Robert Bosch LLC and Stem, Inc. setting forth proposed revisions to Electric Tariff Rule 21 to address interconnection of behind-the-meter, non-exporting energy storage as described in Attachment C, is granted as set forth in Today's Decision.

3. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall file Tier 2 advice letters within ~~30~~60 days of the effective date of today's decision proposing revisions to Electric Tariff Rule 21 establishing a cost envelope of 25% for interconnection-related expenses. This cost envelope shall apply for five -year term. At minimum, the Tier 2 advice letter shall include:

- Interconnection application documentation including cost envelope selection box and "technical scope package"
- Memorandum account details, including explanation about each project expense, how project expenses will be tracked over time and how booked expenses will be netted across projects.

4. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall apply the 25% Cost Envelope to the estimated cost provided by the utility on the Generator Interconnection Agreement (GIA) documentation ~~for~~. In order to inform the GIA to elect the Cost Envelope, projects that ~~elect and successfully complete both the initial and secondary phases of a given Rule 21 study process~~successfully complete either Fast Track Initial Review or Supplemental Review must pay a new $2,500 deposit and allow an additional 20 business days for the Utility to develop a cost estimate

following the completion of the engineering review phase. Developers applying under the Independent Study Process must pay the required deposits and complete both a System Impact Study and Facilities Study in order to elect the Cost Envelope.

5. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall file a Tier 2 Advice Letter within ~~30~~60 days of the effective date of today's decision updating their Electric Tariff Rule 21 generator interconnection application to reflect the "technical scope package" if ~~the developers~~a developer elects to use the cost envelope framework.

6. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall ~~each create~~file a Tier 2 Advice Letter within 60 days of the effective date of today's decision creating a memorandum account to track interconnection costs that are either above or below the 25% cost envelope for reasonableness review for recovery in either a general rate case or in a subsequent application. The memorandum account shall include a description of the main driver(s) of the inaccurate estimate, and an explanation of how the utility attempted to mitigate or take steps to prevent estimates outside of the 25% range. A technical report including comprehensive and detailed information about each entry into the memorandum account shall be attached as an appendix.

7. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall host workshops, in consultation with the Commission's Energy Division, at least semi-annually, to provide a forum for parties and the Commission to inquire about the utilities' interconnection process progress and to provide guidance.

8. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall host a workshop within 120 days of the effective date of today's decision to discuss new data reporting requirements and formats. The utilities shall consult with Energy Division and create a working group to refine metrics and reporting. These metrics shall be added to the Rule 21 Quarterly Report.

9. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall file proposed revisions to Tariff Rule 21 setting forth any agreed-upon technical requirements, testing and certification processes, and effective dates for Phase 2 communication protocols and Phase 3 additional advanced inverter functions in separate Tier 3 advice letters no later than six months from the effective date of this decision.

10. The parties must comply with the filing and event schedule set out in Attachment D.

11. Rulemaking 11-09-011 is closed.

This order is effective today.

Dated ______________________________, at San Francisco, California.

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