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)

CLEAN COALITION COMMENTS ON JOINT MOTIONS OF SOUTHERN CALIFORNIA EDISON COMPANY, SAN DIEGO GAS & ELECTRIC COMPANY, AND PACIFIC GAS AND ELECTRIC COMPANY ON LANGUAGE IMPLEMENTING JOINT COST CERTAINTY PROPOSAL AND REVISIONS TO STREAMLINE RULE 21 FOR BEHIND-THE-METER NON-EXPORTING STORAGE DEVICES

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CLEAN COALITION COMMENTS
ON JOINT IOU COST CERTAINTY AND ENERGY STORAGE
INTERCONNECTION MOTIONS

On April 16, 2015, Administrative Law Judge Bushey issued a ruling setting a schedule for comments on the utility motions for cost certainty and energy storage interconnection. The Clean Coalition here responds to the utility motions and presents an alternative proposal for cost certainty.

The Clean Coalition is a California-based nonprofit organization whose mission is to accelerate the transition to renewable energy and a modern grid through technical, policy, and project development expertise. The Clean Coalition drives policy innovation to remove barriers to procurement, interconnection, and realizing the full potential of integrated distributed energy resources, such as distributed generation, advanced inverters, demand response, and energy storage. The Clean Coalition also works with utilities to develop Community Microgrid projects that demonstrate that local renewables can provide at least 25% of the total electric energy consumed within the distribution grid, while maintaining or improving grid reliability. The Clean Coalition participates in numerous proceedings in California agencies and before other state and Federal agencies throughout the United States.

Our comments are summarized as follows:

Regarding Cost Certainty -

- While interconnection requests have slowed as sufficient capacity has been procured to comply with the 33% RPS requirements, Governor Brown's new goal of a 50% RPS by 2030 and a renewed focus on Distributed Generation, announced in his Jan. 5, 2015 inaugural address, underscores the importance of effectively addressing the interconnection cost certainty issues identified as a priority in this proceeding. Effective improvements in interconnection processes, including addressing uncertainty in costs, is also aligned with the passage of AB 327 requirements for Distribution Resource Plans, and the Commission's Final Guidance on implementation.

- The joint utilities' Fixed Price Option (FPO) proposal is problematic for a variety of reasons, including its failure to provide any cost certainty for larger projects; the large proposed fee ($10,000); the loss of likely actual cost savings relative to the estimate,[1] the substantial additional time required to obtain the FPO results; and its failure to address other long-identified issues in this already very delayed phase of the proceeding.
- The Clean Coalition broadly supports the approach and reasoning of the ED staff proposal while noting that some areas require further development. We offer recommendations to address those matters.
- We have reason to believe that few if any applicants will opt for the FPO, due to the problems described, as indicated by our initial polling of developers on the FPO proposal.
- The Clean Coalition strongly recommends that the Commission adopt a revised version of the Staff Proposal's Cost Envelope Option (CEO) as an alternative to the FPO proposal. The CEO addresses the problems with the FPO proposal and can provide multiple benefits to a substantially larger number of projects while ensuring more accurate alignment with actual costs.
- We note that the goal of cost certainty is greatly enhanced by early cost predictability, and offer recommendations to strengthen these benefits, including publication of Per Unit Cost Guides to provide greater insight into likely interconnection costs even before an application is submitted.

[1] On average, estimates have historically been 10-20% higher than actual costs determined at true-up. Applicants value certainty, but not the certainty of a higher price,

- We agree with the Staff Proposal's conclusion that additional data will support additional improvements and offer greater benefits to applicants and ratepayers.
- We support CALSEIA's call for an expanded Pre-Application Report process that would help NEM and NEM-A projects obtain interconnection
- We recommend that competitive practices allowed under the existing tariff can provide improved contract certainty related to both cost and construction schedules while also substantially reducing total costs.

Regarding Storage Interconnection –

- We note that the ISO staff and Storage Interconnection Stakeholder Group have (pending final stakeholder comments) determined that their existing generator interconnection tariff can be applied without significant modification for use with energy storage facilities, and anticipates similar applicability to WDAT tariffs.

- Although little if any interconnection tariff modification may be necessary for existing rules and processes to be immediately applied also to energy storage, significant refinements can and should be made to better accommodate storage facilities, both individually and especially when collocated with generation. We recommend interim use of existing rules, which treat storage as generation while further refinements are pursued without delay.

I. Comments on Cost Certainty Proposal

a. Background

Three and a half years ago the Commission swiftly opened R. 11-09-011 on the Commission's own motion to improve distribution level interconnection rules and regulations and convened parties in an intensive settlement process to address critical issues as quickly as possible. Parties responded and worked diligently to successfully achieve a settlement on procedural changes in the tariff and additional critical issues to be urgently addressed.

Cost certainty issues were scoped in the original 2011 OIR for this proceeding[2] and queued up as an issue in Phase 1 of this proceeding. Cost certainty issues were, however, pushed to Phase 2 of the proceeding (the current phase of the proceeding) as part of the subsequent February 2012 Settlement which specifically identified cost certainty as high priority next steps.[3] The Commission

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[2] R. 11-09-011 OIR dated September 27 2011, p.6:

> Issue 4: Cost Allocation for Infrastructure Upgrades
>
> Review existing infrastructure upgrade cost-allocation rules including, but not limited to, the following:
>
> • Evaluate mechanisms to improve cost certainty around infrastructure upgrades throughout the interconnection study process.
>
> • Evaluate methodologies to allocate infrastructure upgrade costs between generators and ratepayers.

[3] Rule 21 Settlement Agreement

> Sec. H. ***Cost Certainty:*** The IOUs and the Settling Parties agree that the Commission should take into consideration in Phase 2 that resolving the issue of cost certainty is a high priority and that the key issues are: (1) the variability of potential costs, and (2) the potentially lengthy time frame before final costs are known, including the fact that the Revised Rule 21 Tariff allows the developer to execute an interconnection agreement and get interconnected before receiving a final cost estimate.

ATTACHMENT B: Recommended Scope of Phase 2 Issues

> 3. Cost allocation and certainty issues, including but not limited to: earlier cost certainty, cost averaging, cost sharing, distribution system upgrades appropriate for rate-based support, data reporting to improve cost predictability, cost assignment of planned distribution system upgrades, curtailment as a method of

also agreed at the Phase 2 PHC that this would be an expedited proceeding. We are now three years from that date and we still haven't resolved the cost certainty issues. In light of the long record of this proceeding and reflecting the numerous rounds of comments and workshops addressing this issue since 2011 and the subsequent Staff Report in August of 2014, the Clean Coalition recommends a revised Cost Envelope Option for cost certainty issues and is opposes the IOUs' Motion to adopt only a Fixed Price Option's (FPO) with limited applicability and the recommendation to delay consideration of broader eligibility and other issues for yet another phase to this proceeding, to commence one year after finalization of this phase. If the Commission accepts the IOUs' suggested schedule it will result in yet further delay that is not, in our view, reasonable. The Cost Envelope Option can be implemented now, with greater applicability than the FPO.

Last, we note that the Staff Report correctly identifies cost estimate negotiations as a major cause of dispute and delay[4] in the execution of Interconnection Agreements (IAs). We agree that consistent and objective cost estimation practices will greatly reduce the likelihood of disputes. Publishing a Per Unit Price Guide for distribution system facilities and upgrades, mirroring the cost guide already published in relation to the transmission system, would offer increased predictability to applicants. If a Per Unit Cost Guide was applied as a standard pricing basis for all interconnection applications it would support consistency in cost estimates and would reduce the scope of factors commonly subject to negotiation or dispute when seeking to conclude Interconnection Agreements.

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avoiding triggered upgrades, development of an online portal for applying for a Pre-Application Report.

[4] Staff Report on Cost Certainty for the Interconnection Process at pp. 3-5.

The Clean Coalition greatly appreciates Energy Division staff's Proposal and effective efforts to build upon the thoughtful prior contributions of Parties. We share the staff's expressed expectation[5] that the proposal does offer significant improvements toward achieving the goals of this Proceeding, and support the Proposal as a stronger foundation for meeting the goals of this proceeding. As reflected in the staff proposal[6], and as noted in our prior comments[7], a primary public benefit of increased certainty is to reduce the costs associated with interconnection, costs which are ultimately reflected in the price of energy[8] and thereby borne by ratepayers.

The Staff Proposal incorporated both the utility fixed price option and the cost envelope option for other projects, proposed by IREC and modeled on the Massachusetts interconnection process. As discussed in our Opening Comments on the Staff Proposal[9], the fixed price option proposed by the utilities may be

[5] "Under the proposals presented herein, staff expects that there will be improved cost certainty that can help level the playing field between utilities and prospective project applicants and mirror the frictionless interconnection process enjoyed by NEM program eligible applicants." (Staff Proposal, p. 5)

[6] At page 3: "Cost estimate changes and time delay uncertainties create uncertainty in an applicant's ability to plan a business. Moving through a complex process without being able to communicate cost certainty to collaborating parties increases project costs all around. These increased project costs potentially are negatively impacting ratepayers who, as off takers in a PPA, may end up paying higher energy costs resulting from this uncertainty."

[7] Clean Coalition Reply Comments on Staff Proposals for Cost Certainty & Response to Questions Regarding Issues, Priorities and Recommendations for Energy Storage Interconnection; filed in this proceeding R. 11-09-011, September 26, 2014

[8] For example, if the resulting cost certainty allows the offered/accepted cost of energy (the PPA rate) to be just 0.1¢/kWh lower due to reduced development risk and associated lower financing and investment costs, ratepayers would save $32,000 over a 20 year contract for each MW(Assuming 1600 MWh/MW capacity per year for 20 years). These ratepayer savings every 10 MW of new capacity would offset a $300,000 unanticipated deficit.

[9] Clean Coalition Opening Comments on Staff Proposals for Cost Certainty & Response to Questions Regarding Issues, Priorities and Recommendations for Energy Storage Interconnection; filed in this proceeding R. 11-09-011, September 12, 2014.

viewed as a type of cost envelope in terms of a fixed price being a zero percent cost envelope, however offering a cost envelope allows applicants to pay, and the utility to recover, the actual costs incurred up to the limits of the envelope when ever these costs differ from the utility estimate. While a fixed cost option as proposed by the utilities may be retained to gage market interest in what is essentially a 0% price variation option within the cost envelope approach, the use of a cost envelope allows cost certainty to be extended to a broader range of projects while reducing disincentives to applicants. While a fixed price will result in actual over or under charges for each project that must be addressed, a cost envelope will result in the applicant paying the actual costs, and benefit from actual savings, to the extent that actual costs lie within the envelope range of the utility estimate. Improving cost certainty in this manner is anticipated to not only reduce the potential for ratepayer liability, while yielding the net ratepayer benefits previously noted.

The Clean Coalition addressed the matter of a balancing account and other issues in Attachment 3 of our September 2014 opening comments on the Staff Proposals;[10] these recommendations remain relevant to adoption of any cost certainty proposal.

b. The revised Cost Envelope Option

Given the limitations of the Fixed Price Option, described further below, we urge the Commission to instead adopt a revised Cost Envelope Option (CEO) that is generally in line with the Staff Proposal recommendations from August, 2014,

[10] Ibid.

and reflects the approach adopted in Massachusetts and proposed by IREC and the Clean Coalition in prior workshops and comments.[11]

The Clean Coalition supports the Staff Proposal's cost envelope approach with the following modifications and clarifications, in what we label the revised Cost Envelope Option or CEO. Taking into consideration concerns raised by the IOUs and various other parties, we recommend the following revisions to the Staff Proposal's cost envelope approach. The key features of our proposed revisions are: 1) As argued in our prior comments we continue to recommend expanded applicability for any Fast Track or ISP projects, irrespective of the Fixed Cost Option, with limited exceptions for projects that are projected to have anomalously high or novel interconnection costs; 2) shifting the risk of any amount over the 10-25% envelope limit into a balancing account rather than imposing shareholder liability (addressing a primary objection of the IOUs, and reducing the unintended incentive to produce higher cost estimates identified in our prior comments) and adding, as a backstop, ratepayer liability for any long-term overdraw of the balancing account, to be addressed every three years in the IOU general rate case.

These changes achieve the following important objectives: 1) simplicity; 2) expanded applicability; 3) largely maintaining assignment of actual costs to applicants while addressing uncertainty.

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[11] The Clean Coalition first submitted proposals for improved cost certainty and accelerated cost determination in October of 2011 when these issues were scoped within the Settlement. These proposals were developed further in our October 2012 response to the Amended Scoping Memo, and we recommended a 25% cost estimate exceedance cap in our presentation at the November 13th 2012 and the March 5th 2013 Rule 21 workshops on cost certainty, which were reflected in the August 2014 Staff Proposal.

These changes achieve the following important objectives: 1) simplicity; 2) expanded applicability; 3) largely maintaining assignment of actual costs to applicants while addressing uncertainty.

The CEO can provide multiple benefits to a substantially larger number of projects than the FPO while ensuring a better match between estimates and actual costs.

The key features of our Cost Envelope Option are as follows:

1. The revised CEO would be available to all projects that pass Fast Track or ISP, or NEM-A projects applying under the NEM portion of the Rule 21 tariff.

   Many bioenergy projects that won't qualify under the FPO due to the dollar limits applied by the FPO will also qualify for the CEO.

2. No dollar limits are imposed on CEO applicants but we include the "no substation upgrades" criterion that is also part of the FPO.

   It is arbitrary to create a bright line offering cost certainty to one project, estimated at $500,000, but deny it to another that is estimated to cost $1 more, especially since this eligibility is based upon the estimate provided by the IOU with an unknown degree of consistency – identical projects may be denied eligibility based on luck of the draw in personnel performing the estimate.

   If a cost limit is to be applied, it should be applied so as to still offer some certainty to projects exceeding the FPO's proposed $500,000 cap that would exclude the majority of ISP applicants and virtually all projects associated with bio-energy or greater than 4 MW. For example, higher cost projects may only be eligible for a broader cost envelope (25%), still providing a meaningful level of certainty while allowing for greater deviation from the utility estimate without impacting the balancing account. Based upon review of the historic interconnection cost data provided by the utilities in response to the 2012-2013 Joint Discovery Requests, less than 1% of projects' actual costs exceeded estimates by more than 20%, although each project has been required to bear the full responsibility of this possibility.

3. At any point prior to entering into an Interconnection Agreement, the applicant may elect either a 10% or 25% CEO as an alternative to the default interconnection estimate and true-up cost assessment approach.

Electing the 10% CEO means that final costs will be limited to plus or minus 10% of the estimated costs; the 25% CEO means costs be limited to plus or minus 25%. Some parties may prefer the broader range in the expectation that actual costs will come in up to 25% lower than estimated, as has typically been the case; While we do not oppose allowing a 0% fixed cost option comparable to the utility proposal, forgoing the likely benefit of actual costs being lower will effectively add a significant cost to applicants and act as a major disincentive against securing cost certainty.

4. Electing the CEO will trigger an additional 30 business days for the utility to generate the CEO report (for both 10% and 25% options).

This is discussed in more detail below. While we propose no penalties for exceeding 30 days, when this target is not achieved it should be noted and explained in the Interconnection Data Quarterly Report to assist in identifying future areas for improvement.

5. Upon completion of interconnection engineering and construction, applicants will make any additional payments required to pay the full actual costs, but no more or less than the cost envelope estimates provided.
6. Net costs or net excess payments, if any, beyond the cost envelope range realized in total across all projects for each utility, will be rate-based (no shareholder liability, as the Staff Proposal recommended).

We anticipate, based on available interconnection study data, that there will be net excess payments rather than ratepayer liabilities because historical interconnection cost estimates are higher than the actual costs for the large majority of projects (based on data request responses in this proceeding).

7. Fast Track and NEM-A projects will require a refundable $5,000 deposit for the CEO, ISP projects $8,000, and NEM-A $2,500.

The amount refunded will be determined by the actual work performed. In no cases will applicants be required to pay more than the deposit for the CEO estimate. The required deposit will be adjusted over time based upon the actual costs of producing the CEO estimate. The CEO requires the utility to perform tasks that would otherwise occur after completion of an Interconnection Agreement; the deposit is intended to cover this work, reducing the total remaining tasks and associated charges later in the process.

8. Each utility will publish annually a Per Unit Cost Guide reflecting facility component and installation costs to promote increased transparency and consistency in the development of cost estimates, and to provide applicants with publicly-available information to anticipate likely interconnection component costs associated with common facilities and configurations.
9. The Commission will retain an Independent Evaluator to ensure that utility CEO estimates are accurate and consistent.
10. To further ensure that costs are accurate and reflect market efficiencies achieved through competition, utilities shall not unreasonably withhold approval of the third-party option ("Third-party installations") for building facilities and upgrades.[12] Applicants seeking to use third parties for interconnection upgrades may be able to obtain substantially lower costs than under the default utility option.

Adding some more detail with respect to the third-party option, we note that the issue of cost certainty would be largely obviated if customers had the opportunity to seek competing bids from approved independent third party contractors to perform the work required by the controlling utility and defined in the applicable Interconnection Agreement. While the utility may prefer not to be bound by a firm contract price or schedule, independent Engineering,

[12] The current tariff gives use of third parties to the discretion of each utility. For example, Per ELECTRIC RULE NO. 21, PG&E 32002-E (2014), I.2 - THIRD-PARTY INSTALLATIONS:

"Subject to the approval of Distribution Provider, a Producer may, at its option, employ a qualified contractor to provide and install Interconnection Facilities or Distribution Upgrades, to be owned and operated by Distribution Provider, on Distribution Provider's side of the PCC. Such Interconnection Facilities and Distribution Upgrades shall be installed in accordance with Distribution Provider's design and specifications."

Procurement and Construction (EPC) contractors are generally ready and willing to offer firm and highly competitive bids. These firms currently perform the same interconnection work under contract to utilities, and for the interconnection customers where such work is required on the customer's premises and/or the customer side of the point of common coupling (PCC).

The Imperial Irrigation District, as a public utility, explicitly allows third party contracting in its transmission interconnection tariff[13], and approved five major interconnections in 2014 in which the customer utilized this option, including circuit and substation upgrades.[14] There is, accordingly, a good precedent for what the Clean Coalition is recommending with respect to third party interconnection upgrades.

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[13] IID Standard Generator Interconnection Agreement Article 5. Interconnection Facilities Engineering, Procurement, and Construction.

5.1. Facilities and Cost Estimate. The Interconnection Facilities, Network Upgrades, and Distribution Upgrades (including Common Upgrades) required to interconnect the Generating Facility to the Transmission Provider's Transmission System shall be set forth in Appendix A (Interconnection Facilities, Network Upgrades and Distribution Upgrades). The Transmission Provider's estimate of the costs of Transmission Provider's Interconnection Facilities, Network Upgrades and Distribution Upgrades (including Common Upgrades) also shall be set forth in Appendix A (Interconnection Facilities, Network Upgrades and Distribution Upgrades). *Where the Parties have agreed, pursuant to the negotiation process in Section 11.2 of the Transmission Provider's GIP, that the Interconnection Customer shall be responsible for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand-Alone Network Upgrades, Appendix A (Interconnection Facilities, Network Upgrades and Distribution Upgrades) shall identify the Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades which Interconnection Customer is obligated to design, procure and construct at Interconnection Customer's expense,* subject to Interconnection Customer's right to receive transmission rate credits in accordance with Article 11.5 of this GIA. [Emphasis added]

For further detail see Sec. 5.3.4 – 'General Conditions Applicable to Interconnection Customer's Responsibility to Build' included as Attachment 2

[14] IVSC2 Sun Peak Solar GIA-0414-25, Regenerate Seville Solar GIA-0414-26, Green Light Energy Sonora 080911 GIA-0811-18, Green Light Energy Alhambra 040312 GIA-0811-17, & Green Light Energy Arkansas 040312 GIA-0412-20.

Expanded applicability

We urge the Commission to make the Cost Envelope approach an option for all Fast Track and ISP applicants, with an exception for projects that the IOUs feel are likely to have anomalously high interconnection costs. As mentioned in our opening comments, under the current Staff Proposal many Fast Track projects could be "orphaned" and not eligible for the Fixed Cost option or Cost Envelope option. As with the Staff Proposal regarding novel interconnection configurations, we would recommend limiting the number or percentage of projects for which a utility may annually elect to exclude from the Cost Envelope approach, and suggest an annual limit of 5 projects or 5% of projects, which ever is greater, and subject to review by Advanced Interconnection Consultation staff.

Costs and balancing account issues

The Clean Coalition also recommends that a balancing account be created by each utility that will cover costs in excess of the 10% cost envelope incurred by projects after signing of the GIA. In order to ensure that the balancing account remains solvent over time, any overcharge should be trued up every three years in each IOU's General Rate Case, as the IOUs describe in their Supplemental Filing submitted on May 8, 2015.

While the risk of significant cost shifting to ratepayers appears minimal based on the utility record regarding interconnection costs, even such limited risk may be reduced in a number of ways. First, we should consider that ratepayers would benefit from some reduction in the cost of project development associated with increased cost certainty.[15] Beyond this likely net ratepayer benefit, IOUs could be

[15] For example, if the resulting accelerated development and reduced risk allows the offered/accepted cost of energy (the PPA rate) to be just 0.1¢/kWh lower, ratepayers would save $32,000 over a 20 year contract for each MW, enough to offset a $300,000

required to reduce the full value of refunds to developers for interconnection costs that turn out to be lower than estimated in the GIAs, instead of refunding these amounts in full, or an amount sufficient to maintain the utility's balancing account may be held back. Alternatively, a very modest cost estimate accuracy insurance fee may be assessed to amortize the actual risk of costs exceeding the 10% envelope.[16] If the account develops an ongoing surplus, these excess revenues may be distributed proportionately to contributors.

These measures would provide cost certainty without shifting cost allocation between customer classes, or even significantly between applicants. The fundamental public benefit achieved through the resulting increased certainty and accelerated decision processes far outweigh the negligible and mitigated risk to ratepayers, and the reduced development risk across innumerable projects will result in lower energy costs for ratepayers that will likely far exceed any costs.

As shown in Figure 1 below, we note that California continues to have significantly higher installed costs than other markets nationally, and internationally the difference is even more pronounced, despite comparable labor and equipment costs. High risks and associated costs related to interconnection are both a contributing factor to these higher interconnections but also an opportunity for improvement.

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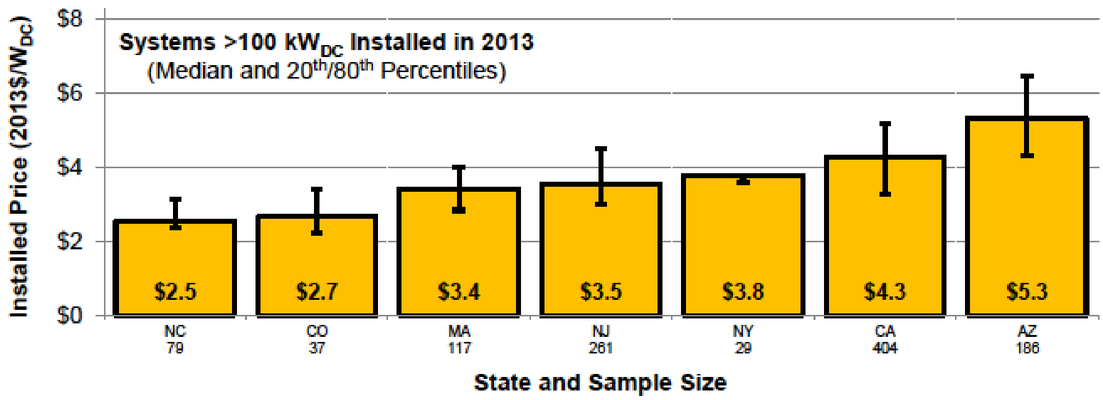
unanticipated deficit on every 10 MW of new capacity (Assuming 1600 MWh/MW capacity per year for 20 years = 32,000 MWh).

[16] For example, a 1% fee would be sufficient to cover the full liability of every 10th project exceeding its cost envelope limit by 10% (20% above the estimated cost). Based on data received by the Clean Coalition in 2012, utility cost estimates have been 6-18% above actual costs, showed few projects exceeding estimates by 10%, and no projects exceeding estimates by more than 25%. This risk would be further mitigated by the proposed exclusion of the highest risk projects from cost certainty protection as separately proposed.

Figure 1. *Comparative Installed Costs of PV Systems in Major U.S. Markets.*[17]



The same Lawrence Berkeley National Lab report concludes:

> Lower installed prices in other major international markets suggest that deeper near-term soft cost reductions in United States are possible. Although such reductions may accompany increased market scale, it is also evident that market size alone is insufficient to fully capture potential near-term cost reductions (as suggested by the fact that many of the U.S. states with the lowest installed prices are relatively small PV markets). Achieving deep reductions in soft cost thus likely requires a broad mix of strategies, including: policy designs that provide a stable and straightforward value proposition to foster efficiency and competition within the delivery infrastructure, [and] targeted policies aimed at specific soft costs (for example, permitting and interconnection)

Applicability of the CEO

Even by allowing nearly all Fast Track and ISP projects to be eligible for cost certainty, as our revised CEO does, eligibility among all project applicants is still limited. Table 2 shows updated Clean Coalition-compiled data, from IOU quarterly reports, for the reformed Rule 21 process, from September 2012 through the third quarter of 2014, showing very low Fast Track success rates. In total, 67% of Fast Track applicants fail Initial Review, and 50% of those choosing to pursue Supplemental Review also fail. As a result, less than 1/3rd of projects

[17] Tracking the Sun VII: The Installed Price of Photovoltaics in the United States, Lawrence Berkeley National Laboratory, September 2014.

applying to Fast Track are found eligible, although many may proceed under ISP. For this reason, cost certainty applicability under ISP is a very important factor, and the Joint Utility proposed $500,000 cap on interconnection costs is estimated by the IOUs to exclude approximately 2/3rds of projects that would potentially benefit from any cost certainty option.

Table 1. *Fast Track Application Success Rates.*

Sept 2012 - Sept 2014	FT export Applications	# passing Initial Review	# failing IR	Supp. Review Applications	# passing SR	**Total passing**	GIA signed*
SCE	100	17	53	15	11	**28 (28%)**	10
PG&E	136	3	103	89	44	**47 (35%)**	16
SDG&E	13	0	11	6	1	**1 (8%)**	5

* = may include applications prior to Sept 2012

Table 2 compares the CEO proposal to the FPO proposal.

Table 2.

	Applicability	**Fee/deposit**	**Timeline**
CEO	Projects passing FT or ISP; no substation upgrades	Deposit: $5,000 Fast Track/$8,000 ISP	30 additional Business Days
FPO	Projects passing FT or ISP; no substation upgrades; under $500k upgrade costs	Fee: $10,000 for both FT and ISP	60 additional Business Days (3 months calendar time)

Comments on the Fixed Price Option (FPO)

We provide here some additional comments on the utilities' Fixed Price Option, adding to what we have already provided in previous rounds of comments.

c. The Fixed Price Option

Eligibility is too narrow for the FPO

The FPO is limited to projects that pass Fast Track or ISP, with no substation upgrades and total interconnection costs (for Interconnection Facilities and Distribution Upgrades) under $500,000. For a Fast Track project up to 3 MW this equates to $134,000 per MW. For ISP projects up to 5 MW, this dollar limit equates to $100,000 per MW.

Based on available data, the $500,000 limit is overly restrictive because it will eliminate a large number of projects from eligibility for the FPO. The mean interconnection cost for Fast Track projects, based on data received from the IOUs in 2012 in response to Clean Coalition data requests, was $166,000/MW (see Attachment 1 below). As described above, we suggest instead the CEO approach, which provides somewhat less certainty (a cost range instead of fixed cost numbers) in return for broader eligibility. The risk to ratepayers of broader eligibility is in our view largely mitigated through the averaging approach of underages and overages, and available data suggests that there is a significant utility tendency toward providing estimates that are higher than actual costs. Given this data it is likely that ratepayers will not be liable for interconnection costs frequently or perhaps ever because of accumulated payments higher than actual costs.

As noted by the Bioenergy Association of California (BAC) and Placer County Air Pollution Control District (PCAPCD), the variability and uncertainty in interconnection costs is a major impediment to development of these projects, which is a significant factor in our recommendation to lift the $500k interconnection cost limit. We believe that the averaging approach we've recommended will substantially mitigate ratepayer risk from eliminating this cap.

Fixed Cost fee

The proposed $10,000 fee for the FPO creates an unwarranted deterrent. We understand that the rationale is to bring forward design work that would occur under the normal process after the GIA is signed. However, the basis for the $10,000 figure has not been established in the record, and excessive costs will be a strong deterrent to parties considering the Fixed Cost option, particularly when combined with the far longer timeframe required for the Fixed Cost option.

In order to lower this hurdle we suggest that the proposed fee be instead define as a "deposit" to cover any additional costs associated with cost estimation that the utility will incur in advance of a GIA and not already included in application and study fees. Any funds in excess of those required for this additional work will be credited toward work performed after the GIA, or refunded it the applicant does not elect to enter into a GIA. While it should be acknowledged that early determination of costs may create some expenses beyond those that would otherwise be incurred subsequent to a GIA, imposition of a $10,000 "fee" will only serve to ensure that anyone seeking cost certainty will pay $10,000 more than they would on average for the same interconnection under current practice; for smaller projects this could represent a guaranteed increase in interconnection costs of more than 10%. Significant additional costs and delays will clearly discourage applicants from taking advantage of this option and realizing any improvement in the interconnection process, therefore the Commission should aim to keep costs low and processes expedited.

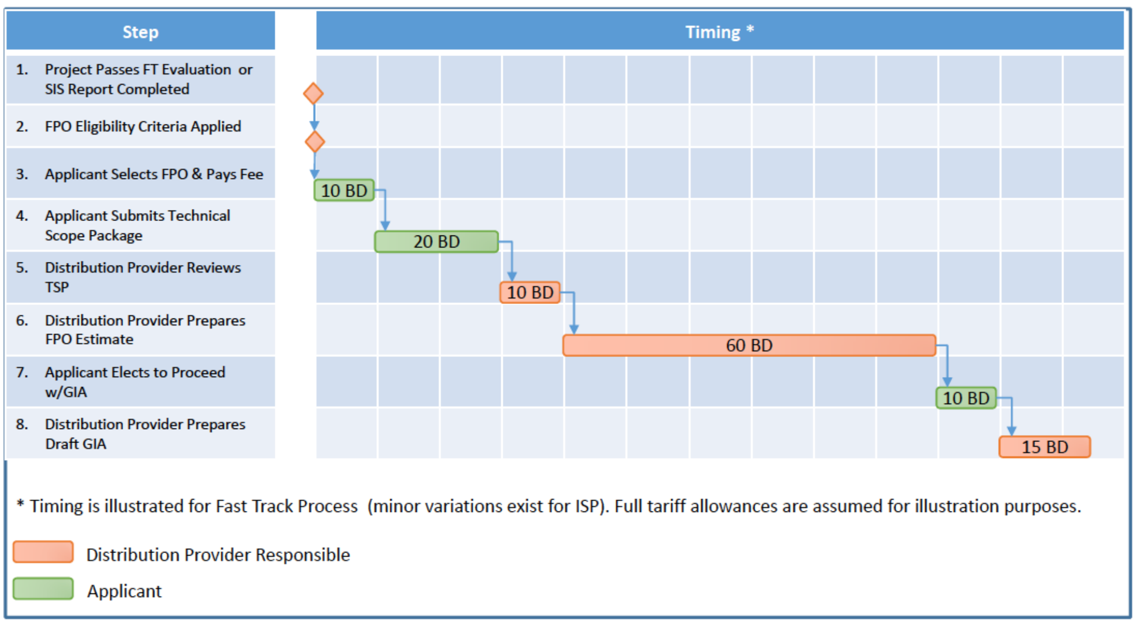
We also recommend, more importantly, that pricing for the Fixed Cost or Cost Envelope options be reduced to $8,000 for ISP, $5,000 for Fast Track, and $2,500 for NEM-A projects, unless evidence is provided that a higher deposit is warranted. As the IOU proposal acknowledges, the fee or deposit will need to be adjusted over time to reflect actual costs. Rather than start high and go low, however, as the IOUs recommend, we recommend the above rate structure as an appropriate starting point that should present a significantly lower hurdle for customers interested in the FPO or CEO. Even with these lower fees we still fear that few or perhaps no customers will sign up for the FPO. If this is the case, the work that has been expended on the cost certainty proposals will have been wasted, so there is some incentive to achieve a more attractive FPO structure.

Time required for fixed cost report

Similarly, the timeline for the FPO seems too long to be attractive to applicants. The IOU proposal adds up to 125 business days—equivalent to over five months of calendar time—to the interconnection process, including 60 days to provide the cost certainty estimate (Figure 2). For Fast Track projects this more than doubles the timeline for getting to the GIA. Combining this longer timeline with the high fees for the FPO makes this option not very attractive to developers we have surveyed. While some projects may require more than 30 days to evaluate, it is appropriate to aim for efficient processing of cost certainty requests and support this by setting a target that does not exceed the time typically required to perform the tasks. IOUs have not demonstrated the need for 60 business days, which is a very significant addition to the FT process. 30 business days (six weeks) should provide adequate time for utility staff, especially given the advance notice provided by the application and review schedule prior to beginning the preparation of the cost estimate.

While we propose no penalties for exceeding 30 days, when this target is not achieved it should be noted and explained in the Interconnection Data Quarterly Report to assist in identifying future areas for improvement. As utilities develop their new processes and utilize additional automation technologies we anticipate that the time required will decrease.

Figure 2. *IOU Fixed Price Option timeline (source: Joint IOU presentation).*



We do recognize the benefit of the FPO in terms of eliminating liability for additional interconnection upgrade costs after a project is interconnected, which ameliorates investor concerns about such liability, which is an issue under today's tariffs. However, this benefit is outweighed by the issues just mentioned such that the net benefit of the IOUs' proposal is minimal.

The IOUs' claim that there is insufficient data for the cost envelope approach is inaccurate

The IOUs' cost certainty proposal suggests that there is insufficient data to consider the cost envelope approach advocated by the Staff Report. As discussed at the April 9 cost certainty workshop, in addition to the data already available on interconnections under the reformed Rule 21, the WDAT/WDT interconnection process offers extensive data both prior to and following the Rule 21 reforms adopted in this proceeding. In amending Rule 21 to accommodate wholesale interconnection the Commission aimed to harmonize these separate tariffs, and the Rule 21 tariff update was based upon the existing WDAT/WDT tariff. The emphasis of the new changes was largely procedural, with little if any impact on the actual physical interconnection costs for which we are seeking to provide firm cost estimation. Therefore, we believe that the extensive experience accumulated under years of related and functionally similar procedures do provide very useful data for the current cost certainty discussion, making the need for one additional year of data, as the IOUs propose, seem unnecessary.

The IOUs also suggest that gaining some experience with the FPO will be helpful in crafting a broader approach in a new phase. However, given the problems with the FPO described above it is not clear how many, if any, applicants will apply for the FPO. In our initial surveys of developers none expressed any interest in applying for the FPO. It would be an unfortunate result if we follow the IOU recommendations to defer amendments or alternatives to the proposed FPO until a later phase of this proceeding in order to gain experience with it, only to find that the FPO was little used due to its disincentives. We recommend instead that the Commission adopt the alternative CEO at this time reflecting amendments to the FPO proposal in line with the Cost Envelope approach recommend in the Staff Proposal.

II. Comments on Interconnection of Storage Facilities Proposal

The Clean Coalition agrees with the need to address the lack of clarity regarding interconnection of storage devices in general and the Commission's interest in addressing behind-the-meter (BTM) non-exporting storage without delay.

We appreciate the active efforts each of the utilities have made to engage with stakeholders through a series of meetings, following the December workshop on this topic, and the efforts to respond to feedback opposing the addition of a new screen (H.1), The Clean Coalition supports the good faith efforts to accommodate non-exporting storage through controls to avoid increasing Peak Demand to avoid exceeding distribution system load capacity. However, while parties have developed a common understanding and have moved toward at least partial consensus regarding the applicability of review screens for BTM storage, it has been consistently clear that there is a fundamental disagreement as to the treatment of storage as a special class of customer load and the applicability of Rule 21 to this new load.

We support the reinstatement of an ongoing technical and policy working group for Rule 21 stakeholders, and the IOU proposal for additional time to hold a workshop and address BTM non-exporting energy storage issues. We believe a determination is required by the Commission regarding the applicability of Rule 21 to customer load in order to define the appropriate scope of issues to be addressed. In the interim, we recommend that BTM storage <u>not</u> be subject to the disputed application of screens C and D, which the IOUs have argued should apply to the charging operations of BTM storage.

With respect to FERC Order 792, which, among other things, directed transmission providers to define electric storage devices as generating facilities that can take advantage of generator interconnection procedures, the California ISO has addressed the need for any changes in its interconnection tariff. CAISO determined that, while further refinements may be warranted, it could initially accommodate exporting storage with no changes to the tariff other than the addition of "storage" as an applicable category wherever "generation" was discussed. Load service to storage facilities operating without restrictions would be addressed separately and not under the CAISO Generator Interconnection and Delivery Allocation Procedure (GIDAP) tariff. Likewise, we believe that storage may similarly be readily accommodated under Rule 21 without substantive changes, and any new screens may be deferred for fuller consideration while allowing new storage facilities to interconnect under the existing tariff.

The Clean Coalition strongly supports the use of distributed energy resources (DER) to provide services, improve operation of the grid, and to avoid or defer more costly infrastructure investments that would otherwise be required to accommodate increasing loads or energy exports to the distribution system. We are actively engaged in the proceedings addressing development of Distribution Resources Plans (R.14-08-013), Demand Response (R.13-09-011), and Integrated Demand Side Management (R.14-10-003). Energy storage devices, including non-exporting behind-the-meter energy storage, can contribute greatly to grid operations and yield net ratepayer benefits. These benefits will be realized by offering compensation in exchange for the value they provide, as is being developed in the aforementioned proceedings. Additionally, rate design is being considered to better reflect the cost of service associated with customer behavior, and to encourage behavior that reduces capacity and operational costs.

However, rate design, pay-for-performance compensation, and regulations regarding provision of load service is quite separate from generator interconnection, and should remain so. To the extent that storage devices act as generators, providing power to serve behind the meter loads or exporting it, they should be subject to the same treatment as generators under Rule 21. To the extent that storage devices may act as loads served by the grid, they should be subject to the same standards and requirements applied to any other customer load.

Screens C (“*Is the Starting Voltage Drop within acceptable limits?*”) and D (“*Is the transformer or secondary conductor rating exceeded?*”)[18] are clearly intended to address generator impacts, not the impact of customer loads, and therefore should only be applied to storage devices when they are operating in “generation” mode.

The Joint Utilities state that “Rule 21 is the most appropriate and efficient mechanism to study the charging aspects of energy storage since the generation-like aspects of energy storage must already be studied through Rule 21, and these revisions to Screens C and D support a harmonized approach to studying both the charging and discharging aspects of energy storage for grid safety and reliability.”[19] While addressing both the potential load and generation issues under a single application and tariff may appear to streamline the process, it is far from clear that these distinct energy storage operations should fall under the same tariff framework. The fact that storage devices perform operations regulated by more than one tariff does not mean that all potential operations from these devices should be shoehorned into regulation by a single tariff. To the contrary, blurring the line between these features may lead to very significant broader complications that should not be ignored for the sake of perceived expediency. Applying Screens C and D of Rule 21 tariff to customer load, as proposed by the Joint Utilities creates a new additional test for projects to navigate. Rather than removing a barrier to interconnection of storage, the results of an additional load test can only add complication and expense, and begins a precedent for similar treatment of other customer loads.

[18] Rule 21 Interconnection Screens C and D, pp. 124-125
http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf

[19] Section III A of the Joint Motion on Revisions to Streamline Rule 21 for Behind-The-Meter, Non-Exporting Energy Storage Devices

We agree that the primary responsibility of the utilities is toward the safe and reliable operation of the electricity grid, and it is appropriate to evaluate customer requests with this in mind. However, rules have already been established regarding the supply of energy to a customer to meet their loads and the capacity of the system to supply that demand. Screens C and D have been designed to address impacts that are incidental to the operation of generators such as synchronous devices, and the export of energy to the grid. These effects are distinct from the ordinary customer loads associated with charging a battery system.

Fundamentally, if a customer receives service to meet their onsite loads, and operates within the bounds of that service agreement, no additional test, screen, or application should be required regarding their use of that load service. To the extent that operation of a battery behind the customer's meter is electrically indistinguishable from operation of other loads and devices, it should be subject to the same standards and requirements. A customer's charging of the battery on their electric vehicle does not trigger interconnection review, and the use of a comparable battery in a stationary non-exporting application should not be subject to different treatment.

III. Conclusion

Offering the ability to enter into a Generation Interconnection Agreement with certainty regarding the maximum final cost liability is a very important factor in allowing projects to obtain financing and to do so at lower rates. Determining these costs earlier in the initial project feasibility and application process is equally important in addressing project viability and reducing the high rate of application withdrawal. Early cost determination remains an important issue for this proceeding separate from the current proposals for achieving cost certainty at the completion of the study process.

We appreciate the Commission's attention and Parties diligent work in addressing the issues associated with interconnection in general and cost determination in particular, and offer these comments to further those ends.

Respectfully submitted,

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Attachment 1

List of Clean Coalition and joint parties' data requests and responses from IOUs

The Clean Coalition and a number of other parties (Vote Solar, IREC, Sustainable Conservation, Sierra Club and Absolutely Solar) submitted discovery requests to each of the IOUs in November of 2012. We submitted follow up requests in January and April of 2013, as follows:

- Joint Party discovery requests to SCE, PG&E and SDG&E (individually), November 14, 2012
- Joint Party follow up discovery requests to SCE and PG&E, Jan. 7, 2013
- Clean Coalition follow up discovery request to SCE and PG&E, April 24, 2013

The IOUs have submitted a number of responses to our requests, providing cost data on all projects between 2009 and 2012, and detailed cost correlation information on 80 sample projects.

- PG&E response to Nov. 14, 2012, discovery request on Dec. 14, 2012
- SDG&E response to Nov. 14, 2012, discovery request on Dec. 14, 2012
- SCE response to Nov. 14, 2012, discovery request on Dec. 17, 2012
- SCE follow up response (after Jan. 4, 2013, meet and confer) on Jan. 21, 2013
- PG&E follow up response (after Jan. 4, 2013, meet and confer) on Jan. 22, 2013
- SCE follow up response with detailed data on 10 projects, Feb. 1, 2013
- PG&E follow up response, with detailed data on 40 projects, Feb. 28, 2013
- SCE follow up response, with detailed data on 30 projects, March 12, 2013

Summary interconnection cost data ($/megawatt) (excluding the 20% highest cost projects as these were unlikely to be developed).

	SDG&E	SCE Rule 21	SCE WDAT	PG&E WDT	Means
Mean	$ 184,742	$ 154,777	$ 112,733	$212,536	**$166,197**
Max	$ 278,706	$ 313,000	$ 215,556	$503,333	**$327,649**
Min	$ 62,133	$ 36,819	$ -	$17,000	**$28,988**
St. Dev.	$ 72,488	$ 69,472	$ 56,515	$118,044	**$79,129**
Median	$ 209,750	$ 146,667	$ 107,200	$191,714	**$163,833**

(Attached separately)

Attachment 2

Clean Co Cost Envelope Option alternative redlines of Rule 21 tariff (01 May 19 2015)

Attachment 3

Clean Co redlines of IOU Rule 21 cost certainty tariff changes (02 May 20 2015)