BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	Rulemaking 11-05-005

CLEAN COALITION AND SIERRA CLUB CALIFORNIA APPLICATION FOR REHEARING OF D.12-05-035

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June 29, 2012

CLEAN COALITION AND SIERRA CLUB CALIFORNIA APPLICATION FOR REHEARING OF D.12-05-035

Pursuant to Public Utilities Code Section 1731 and Rule 16.1 of the California Public Utilities Commission's ("Commission" or "CPUC") Rules of Practice and Procedure, the Clean Coalition and Sierra Club California (Sierra Club) submit this Application for Rehearing of Decision 12-05-035, which was mailed on May 31, 2012. We hereby reserve the federal claims raised in this Application for Rehearing for decision by a federal court in accordance with *England v. Louisiana State Bd. of Medical Examiners*, 375 U.S. 411 (1964).

The Clean Coalition is a California-based advocacy group, part of Natural Capitalism Solutions, which is based in Colorado. The Clean Coalition advocates primarily for vigorous feed-in tariffs and "wholesale distributed generation," which is generation that connects to distribution lines close to load. Clean Coalition staff are active in proceedings at the Commission, Air Resources Board, Energy Commission, the California Legislature, Congress, the Federal Energy Regulatory Commission, and with various local governments around California and the U.S. Sierra Club California (Sierra Club) is a grassroots environmental organization with 150,000 members and ratepayers in California. Sierra Club supports the implementation of the renewable portfolio standard, and feed-in tariffs as important policies to help reduce greenhouse gas emissions.

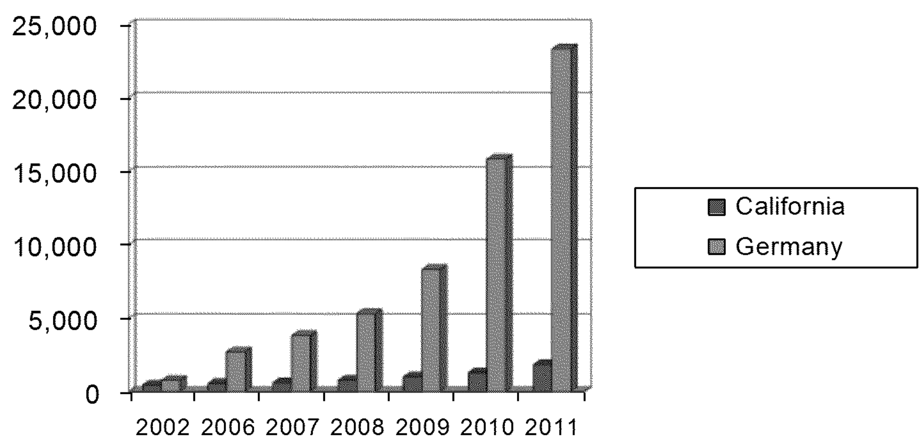
I. Summary

California long ago lost its lead in renewable energy to more forward-looking jurisdictions with respect to this market such as Germany, Italy, Portugal, Texas and now even China. Indeed, even New Jersey has now surpassed California as the top solar market in the U.S.[1]

The Governor has set a goal of 12,000 MW of distributed generation by 2020, but the Commission seems to be actively disregarding this goal. SB 32 was passed in 2009 and required the Commission to create a feed-in tariff for renewable energy projects 3 MW and below. It has been three years since this law was passed and the Commission has still not implemented the law. The Commission has taken a large step in doing so in approving D.12-05-035, but the final approval of the Decision was highly rushed and the Decision contains numerous legal and technical problems that undermine implementation, which we describe below. Much more work remains to be done before SB 32 is an active and viable feed-in tariff program.

The following figure shows how California has progressed in relation to Germany, the world's top solar market, over the last few years. Germany installed 15 times more solar in 2011 than California did, with 70% weaker solar radiation. We are falling further and further behind.

Figure 1. *Comparing Germany and California on solar (RPS, CSI, other programs).*



[1] http://www.slideshare.net/SEIA/us-solar-market-insight-report-q1-2012

The existing feed-in tariff law, AB 1969 (2007), has brought less than ten MW of new renewable energy online, out of a program total of 500 MW. It has clearly failed, due to a variety of reasons, including inadequate pricing in the first few years of its existence and, now, interconnection issues.

California is now at the point where SB 32, passed into law three years ago, is about to be implemented. We can already predict with some confidence that it will fail, like AB 1969 before it, due to the many flaws that we and other parties have demonstrated in the record. Signed contracts are not projects. Signed contracts need to include reasonable pricing, not aspirational pricing. We can't afford to suffer yet another policy experiment doomed to delay or failure. Experiments in new policies that last 4-5 years before failure is realized are not what is needed. California needs effective implementation of tried and true policies.

It is time for California to stop fiddling and create a robust and effective feed-in tariff to not only help meet the Governor's 12,000 MW DG goal but also to regain our leadership in renewable energy. Feed-in tariffs have been shown to work extremely well around the world – and in California in the 1980s and 1990s, during which time we pioneered the feed-in tariff model under PURPA and led the world in renewable energy development. <u>It is not too late to take back our global leadership in renewable energy.</u>

II. Legal Requirements for an Application for Rehearing

The Commission's Rules of Practice and Procedure Rule 16.1(c) states:

> Applications for rehearing shall set forth specifically the grounds on which the applicant considers the order or decision of the Commission to be <u>unlawful or erroneous</u>, and must make specific references to the record or law. The purpose of an application for rehearing is to alert the Commission to a legal error, so that the Commission may correct it expeditiously.

We describe below how D.12-05-035 ("FD" or the "Decision") is both unlawful and erroneous.

This application is timely since applications for rehearing must be filed within 30 days of the decision at issue and the FD was filed on May 31, 2012.

III. The Decision is unlawful

a. The Decision violates SB 32's requirement to provide a price for avoided transmission and distribution costs

SB 32 states (Section 1(e), emphasis added)[2]:

> A tariff for electricity generated by renewable technologies should recognize the environmental attributes of the renewable technology, the characteristics that contribute to peak electricity demand reduction, reduced transmission congestion, <u>avoided transmission and distribution improvements</u>, and in a manner that accelerates the deployment of renewable energy resources.

While the CPUC Staff Proposal recommended a methodology for capturing avoided transmission and distribution improvements, which many parties supported, the FD says only that this is a complex issue and "requires more development" or "additional scrutiny is needed" (p. 34, emphasis added):

> We do not adopt other components of the Renewable FiT Staff Proposal, including the location adder or a transmission adder because we find these components either inconsistent with existing law or <u>require more development</u>. Regarding the transmission adder, we find that the record does not support a determination that the transmission costs for particular RAM contracts constitute the avoided transmission costs for renewable FiT generators under the law. As discussed previously regarding Clean Coalition's suggested location adder, we agree with the concerns expressed by SCE and the other utilities that <u>additional scrutiny is needed</u> before the Commission adopts a location adder.

[2] We note the FD also cites SB 32's Section 1 [illegible] legislative intent guideline is grounded in the legislation [sic] intent set forth in SB encouraging the location of clean generation close to load centers in o electricity."

The FD also fails to include "avoided transmission and distribution improvements" in its list of price requirements on page 16, apparently ignoring the law as chaptered.

This exclusion is a violation of law as SB 32 requires the creation of the program that recognizes the value of avoided transmission and distribution costs. This is not a small issue, as the Commission's own staff proposal and commissioned report from E3 demonstrated: the <u>value</u> to ratepayers from these avoided costs can be as high as 7-8 c/kWh in some areas.[3]

SB 32 requires that ratepayers be indifferent to the costs of the SB 32 program (P. U. Code section 399.20(d)(4)).[4] This means not only that ratepayers are not to pay more for these projects than the avoided cost, but also that ratepayers can't receive uncompensated benefits/value from SB 32 projects. By denying program participants payment for avoided transmission and distribution costs, ratepayers will receive uncompensated value.

At the very least, the Commission must state clearly a schedule for completing these analyses and modifying the SB 32 program accordingly, rather than deferring them to an uncertain future date, as is the case in the FD. The fact that the Commission has taken three years since SB 32 was enacted to reach this point does not inspire confidence that these required additions will happen in a timely manner unless a deadline is set.

[3] Sierra Club recognizes that if the market price under ReMAT achieves a lev requirement of accelerating the deployment of renewable energy resources, at 750 MW, then this [illegible] market price [illegible] sufficient to would stimulate the market to meet th implementing Section 399.20. However, as we state below, the FD leave occur.

[4] Section 399.20(d)(4) states:

> The commission shall [illegible] ensure, consistent with [illegible] and charges, that ratepayers th service pursuant to the tariff are indifferent to whether a ratepaye receives [illegible] service pursuant to the tariff.

b. The Decision fails to provide compensation for mitigation of local environmental compliance costs, as required by SB 32

P. U. Code section 399.20(d)(1) (emphasis added), enacted by SB 32, states:

> The payment shall be the market price determined by the commission pursuant to Section 399.15 and shall include all current and anticipated environmental compliance costs, including, but not limited to, mitigation of emissions of greenhouse gases and air pollution offsets associated with the operation of new generating facilities in the local air pollution control or air quality management district where the electric generation facility is located.

The FD acknowledges that it has failed to implement this portion of the law (p. 38):

> We seek to pay generators the price needed to build and operate a renewable generation facility. We do not find, however, that specific costs, such as compliance costs in a particular air quality management district, are necessarily captured by the RAM methodology [which the FD uses to set the starting price for SB 32]. More analysis is needed.

This passage violates SB 32 in two ways: 1) SB 32 does not direct the Commission to "pay generators the price needed to build and operate a renewable generation facility." This language is nowhere in the law. Rather, SB 32 directs the Commission to follow quite a different price formula and philosophy that better balances the desire for ratepayers to pay lower prices and for developers to be incentivized appropriately, including the ratepayer indifference language already cited; 2) SB 32 makes no allowance for the Commission to pick and choose which portions of SB 32 it will implement and when. The Commission must implement SB 32 in total, including providing compensation for "mitigation of emissions and greenhouses and air pollution offsets…"

At the very least, the Commission must state clearly a schedule for completing these analyses and modifying the SB 32 program accordingly, rather than deferring them to an uncertain future date, as is the case in the FD. The fact that the Commission has taken three years since SB 32 was enacted to reach this point does not inspire confidence that these required additions will happen in a timely manner unless a deadline is set.

IV. The Decision is erroneous in a number of ways

a. The Decision is self-contradictory

The FD contradicts itself when it suggests that the program may be expanded if the program's capacity is subscribed "quickly," because under the schedule the FD creates it is not possible to fully subscribe the program before 24 months. The FD states (p. 68):

> Therefore, today we set as our goal implementing the plain language of the statute and the 750 MW cap noted therein. Our decision today also rests upon our goal of achieving "ratepayer indifference" and cost containment within the program. We are sensitive, however, to the fact that the program's MW may quickly be subscribed. In that situation, we will consider proposals from parties to expand the program.

However, the FD doesn't acknowledge in this section or elsewhere that under the program created by the very same decision, it's not possible for the program to "quickly be subscribed" because the FD intentionally created a system that cannot be fully subscribed in less than 24 months.

We recommend, as in our previous comments, that the Commission create a volumetric, (capacity-based) system of price declines rather than duration-based system like in the FD. Volumetric price degression ensures that costs are contained, particularly if the Commission adopted the Clean Coalition's recommendations for a price floor and price cap along with volumetric degression.

b. The requirement that only projects that entail $300,000 or less in upgrades won't even cover the cost of the Direct Transfer Trips that PG&E is requiring for most projects

The FD changed the PD's "strategically located" requirement such that a project must interconnect to the distribution grid and not incur transmission upgrade expenses over

$300,000 (FD, p. 52). However, in certain circumstances (***see*** **Appendix 1** for a discussion on this issue with PG&E), this expense allowance will be exceeded simply through the IOU requirement to add Direct Transfer Trips (DTTs) to the transmission line, even for distribution-interconnected projects. DTTs costs are estimated at $250,000 each, but this may well go up or down significantly, leading to the possibility that even one DTT will exceed the $300,000 allowance and two will obviously exceed the $300,000 allowance. It seems that this IOU requirement may eliminate a substantial portion of potential SB 32 projects if allowed to remain as is.

We previously recommended instead, that projects be considered "strategically located" if they comprised less than or equal to the minimum coincident load on the substation at issue, in the aggregate with any other projects proposed (Clean Coalition Opening Comments on Proposed Decision, p. 19). We reiterate that recommendation here. The Staff Proposal recommended the same method for defining "strategically located" (p. 23):

> In order to implement this statutory language, staff defines "strategically located" as projects that serve load in order to avoid adverse impacts to the distribution and transmission system. Thus, a project should not exceed the minimum load at the substation. This type of requirement predetermines that the grid is adequate and that the generation will not adversely impact utility operation. In addition, as parties state in the record, the purpose of the interconnection study is to determine the upgrades needed to ensure the generator will not adversely impact utility operation and load restoration efforts. Thus, if this requirement or a similar requirement is implemented, the IOUs cannot deny tariffs based on 399.20 (n)(2) and (n)(4).

c. The FD erroneously suggests that developers can use the IOU interconnection maps to determine whether a project is likely to have transmission impacts

The FD states (p. 53): "We expect generators to use the utilities' Interconnection Maps, available to the public and online, to locate sites that have a low likelihood of transmission impacts. "

As the Clean Coalition wrote in opening comments on the PD, however, this is not possible (Clean Coalition Opening Comments on PD, p. 20). The IOU maps have no data that will help developers determine potential transmission impacts, in terms of how the IOUs determine transmission impacts. This issue is a substantial obstacle to SCE's CREST queue at this time, because all or almost all (it's not entirely clear due to the CREST program's opaqueness) CREST projects are facing transmission impacts even though they are by definition 1.5 MW or smaller. Many CREST projects have had to endure very long waiting periods while SCE studies their interconnection costs, only to find out that SCE simply can't provide a firm estimate of the costs or the time period required to interconnect because of vaguely defined transmission impacts (this issue is known among developers as the "transmission vague" problem). This problem is highlighted by the fact that after four years of the CREST program being available, literally only 5.25 MW of new projects are now online (all solar projects), from an available program capacity of over 200 MW.[5] The FD's directions on interpreting "strategically located" do not resolve this problem or allow SB 32 developers to judge the likelihood of transmission impacts from their new projects.

d. The FD fails to provide sufficient clarity in prescribing allocation of capacity

The FD describes the capacity allocation methodology in an unclear and arguably contradictory manner (FD, p. 49). The FD prescribes equal capacity allocation over 24 months, but it's not clear that each two-month adjustment period has a capacity of the sum of the two months. The FD also specifies that the first allocation period must have a minimum of three MW, but other two-month periods do not appear to have the same minimum. For SDG&E, this means that there could be some periods that have less than 1 MW, which contradicts SB 32's allowance of up to 3 MW per project.

[5] http://asset.sce.com/Documents/Shared/120611_ExecutedCRESTPPAs.xls

The FD also states: "To implement this directive, each utility must divide the total program capacity by 24"; but the FD does not specify in sufficient detail how to handle contracted capacity from AB 1969 FIT contracts. The FD states (p. 69): "We find that all capacity already under contract from the existing § 399.20 FiT Program must be subtracted from each utility's total capacity allocation." However, should the contracted AB 1969 capacity be subtracted from the total SB 32 program capacity for each IOU before allocation to each product type? Or is the whole SB 32 program capacity divided before subtracting AB 1969 contracted capacity from each product type? It appears that the answer must be the former, but additional clarity is needed because this lack of clarity will surely lead to conflicts in implementation, particularly given the consistent history of the utilities interpreting every ambiguity as conservatively as possible. This is a serious omission in the FD in that the allocation is not defined explicitly enough for proper implementation.

e. The FD does not define "initial capacity allocation" or "initial starting capacity" when used as a condition for changes to the tariff price, nor how to address contracts in excess of the remaining capacity for that period

Moreover, the FD does not define either "initial starting capacity" or "initial capacity allocation," and both of these terms are key factors in price increases or decreases. Also, the FD's discussion of price increases (pp. 41-42) uses the phrase "initial starting capacity" and the discussion on price decreases (pp. 43-44) uses the phrase "initial capacity allocation," when it appears that these phrases are meant to refer to the same thing.

The FD also states that "each utility must divide the total program capacity by 24 and then assign one-third into each product type" (p. 44). However, <u>this figure should be 12</u>, not 24, since the FD creates a 24-month long program consisting of 12 two-month periods. Also, immediate problems arise with this methodology in terms of how projects larger than each two-month period's product allocation will be managed. Here is an example:

- PG&E's total SB 32 program allocation is 218.8 MW
- Subtracting 106.5 MW of existing AB 1969 contracts (a figure which may increase by the time the SB 32 program is operational) results in only 112.3 MW for PG&E across all product types
- Dividing by 24 (as the FD directs) results in 4.68 MW per month, divided by three, for each product type, results in only 1.60 MW
- Assuming that "24" should indeed be "12" (because 12 two-month periods were created by the FD) we can adjust this figure upward to 3.2 MW
- As a consequence, does this mean that PG&E must accept the first 3 MW project that qualifies and leave only 0.2 MW for a second project? This does not seem to be a result in keeping with SB 32's mandate of allowing projects up to 3 MW to qualify

The problem is exacerbated even further for SDG&E:

- SDG&E is allocated 48.8 MW for the SB 32 program
- SDG&E has zero AB 1969 contracts signed so the 48.8 MW figure remains the same
- Dividing by 24 (as the FD directs) results in 2.03 MW per month, divided by three, for each product type, results in only 0.67 MW
- Assuming that "24" should indeed be "12" (because 12 two-month periods were created by the FD) we can adjust this figure upward to 1.34 MW
- As a consequence, does this mean that SDG&E must accept the first 3 MW project that qualifies, subtracting program capacity for future two-month periods? Or some other calculation? If one 3 MW project is accepted in the first two-month period, this will exhaust not only the first two-month period's allocation but also the second and part of the third. Does this mean

that pricing decreases by more than $4/MWh or some other result?

- It will be a perverse outcome if each utility limits the available contract size to the particular number for the particular two-month period because there is no way that developers can know in advance what project sizes to develop. 3 MW should be the default contract size because this project size is known in advance and developers can plan accordingly.

The problems with SCE are similar, and perhaps exacerbated further by the fact that the CREST program is seeing a lot of interest at this time and may be fully subscribed by the time the SB 32 program is ready for applicants.

All of these issues constitute errors that require a remedy by the Commission. We recommend, at the least, that any applicant seeking an SB 32 contract be allowed to sign a contract for up to 3 MW if the applicant is seeking that size. As mentioned above, it will be impossible for developers to plan as needed if the allowed project size is completely uncertain.

f. The FD fails to clarify whether the AB 1969 program is suspended or not

SCE submitted a motion on June 21 seeking clarification from the Commission regarding the continuation or suspension of the current CREST (AB 1969) program. Due to the current uncertainty, developers are being told by SCE that new applications are being accepted by SCE only until the end of June. However, the SB 32 program is highly unlikely to be operational until close to the end of 2012, and possibly later, due to many additional program details that need working out, such as the Power Purchase Agreement. This is a key oversight in the FD that needs to be remedied.

The Clean Coalition recommends, contrary to SCE's recommendation, that the AB 1969 programs remain open until the SB 32 Power Purchase Agreement is approved. This is the case because it may be many months past June 30 before the new SB 32 program is operational, particularly given the lengthy delays heretofore in this proceeding. The Governor's 12,000 MW DG goal would seem to mandate greater speed than has been the case in implementing SB 32, and we hope this is the case in the duration of this proceeding.

g. Miscellaneous errata

There are numerous typographical errors, wording/grammar mistakes, etc., in the FD, some of which may cause confusion in implementation. These errors, and the other issues discussed above, show that proper care and consideration were not taken in crafting this FD; nor did it receive sufficient stakeholder review. In particular, the FD was issued a day before it appeared before the Commission for a vote, with substantial revisions subsequent to the Proposed Decision and subsequent to an all-party meeting where parties were given extremely limited time to comment on the PD, with almost no time for discussion. While the implementation of SB 32 has, from the Clean Coalition's perspective, been delayed unconscionably, the Commission added to the problems with implementation by producing the FD in a last-minute manner with numerous errors and inconsistencies, particularly after some parties had requested a hold before the FD went to the Commission for a final vote.

Specifically, we identify the following issues:

- "Bid Fee": There is no bidding in the system created by the FD, so this should not be called a bid fee. We suggest it be called a "queue fee." The FD should also specify when this fee must be paid.
- The FD uses the terms "developer", "seller," "generator," and "sponsor" interchangeably. This terminology should be made consistent across the Decision and we recommend using "seller" as the simplest term and consistent with the terminology in the proposed Power Purchase Agreement.

- Similarly there is no definition of "developer" for use in the Re-MAT price adjustment criteria ("five different developers in the queue"). The Decision's discussion regarding seller concentration attempts to address this, but the Re-MAT provides no guidance on how to prevent developers from easily working around this restriction by creating different entities, etc. Clear criteria for "developer" should be included in the Decision.
- P. 95: Second instance of "Clean Coalition" in middle paragraph should be "Solutions for Utilities" since that clause refers the Solutions for Utilities Petition for Modification, not Clean Coalition's previous motion.

I. Conclusion

For the various reasons described above, the Clean Coalition and Sierra Club California submit this application for rehearing urging the Commission to reconsider many aspects of D.12-05-035. We also urge that the Commission address the issues we've identified in a timely manner in order to avoid additional undue delays in program implementation.

Respectfully submitted,

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Dated: June 29, 2012

VERIFICATION

I am an attorney for the Clean Coalition and am authorized to make this verification on its behalf. I am informed and believe that the matters stated in the foregoing pleading are true.

I declare under penalty of perjury that the foregoing is true and correct. Executed this 29th day of June, 2012, at Santa Barbara, California.

Tam Hunt

Clean Coalition

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Appendix 1: Correspondence between Tam Hunt and PG&E's Chase Sun re DTTs

June 11, 2012

Hi Will, the issue of DTTs has come up a few times in the past year and we're trying to learn more about PG&E's requirements and estimated costs. Could you provide us the guidelines by which PG&E assesses the need for DTTs? Also, is the cost always $250k at this point in time?

Thanks!

Tam Hunt, Policy Advisor and Attorney
Clean Coalition
(805) 214-6150

June 19, 2012

Tam: Sorry about the delay. There are two conditions for DTT. The first is fault detection and the second is anti-ialanding. DTT is required to insure that the generator will not back feed a fault or keep the line energized under an abnormal condition. Both are safety considerations. For estimating purposes, the unit cost for DTT is $250,000 per transmit/receive pair. The actual cost may vary. In addition, for large PV units, we have developed the following guidelines:

PV DTT is required

under the following

conditions: Non-certified

units

For non-certified units the DTT requirement will be consistent with typical generation requirements.

- The PV unit cannot detect and clear an "end of line" (EOL) fault within 2.0 seconds*, Or
- The aggregate generation, including the proposed PV generation, on the line section exceeds 50% of the daytime minimum annual line load,

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Certified units
>2MW

- The PV unit cannot detect and clear an "end of line" fault within 2 seconds,* Or
- The aggregate generation, including the proposed PV generation on the circuit exceeds 50% of the line section daytime minimum annual line load.

- For units directly connected to the distribution bus via a dedicated tie line, and PG&E owns the line, DTT may be required from the station feeder breaker to the PV facility if the PV cannot see an EOL fault.*

≤ 2MW (*Assume PV cannot detect and trip for an EOL fault and fails SGIP "Fast track Process" screen*)

- The circuit or substation has other significant synchronous or induction generation. (> 10% of the proposed generation),

Or

- The circuit or substation has other significant PV generation that uses a different method of islanding detection and is > 10% of the proposed generation.

- For units directly connected to the distribution bus via a dedicated tie line, and PG&E owns the line, DTT may be required from the station feeder breaker to the PV facility if the PV cannot see an EOL fault.*

*** If the PV can prove it will trip offline within 2.0 seconds of the supplying feeder breaker opening the DTT requirement may be waived.**

Please let me know if you have any questions. Thanks.

Chase

June 19, 2012

Great, thanks Chase. Our concern is that these DTT requirements may eliminate many PG&E projects from eligibility for SB 32 because if two DTTs are required (or perhaps even one if costs go over $250k), this will exceed the $300k limit for transmission upgrades that D.12-05-035 enacted.

Could you let us know how many projects 3 MW and below, in your current queue, are being required to install DTTs?

Is it possible for PG&E to more clearly limit when DTTs are required for projects 3 MW and below? Our understanding is that SCE does not have a similar requirement. Is this because their system is different or because their criteria are more lenient on this issue?

Sincerely,

Tam Hunt, J.D.

June 21, 2012

Tam: I believe you may need to differentiate between DTT. The distribution on DTT
latter is transmission work ... not the former. ... on the DG are
considered interconnection cost and not ... system DTT upgrade ... cost. ... expensive
any DTT requirement needed ... to approved ... reviewed ... System Protection
necessity before being issued.

I checked with Roger Salas ... SCE ... right, the SCE DTT uses ... DTT on
only. The burden is up to the developer ... situation ... off line duri

PG& is aware of the inadequacy of the 1547 certification ... standards ...
not test for multiple inverters when there are almost always mu
system. Nor do they ... adequacy for ... islanding schemes when there are sy
generators present on ... the feeder ... certification did not test for the
synchronous generator conditions, PG&E does not believe ... situations certification
where these conditions ... PG&E is relying on minimum load and/
there is no unintentional islanding ... situations ... evolving area with
unknowns. PG&E also has to ... protect customers and the public again
and PQ issues due to ... will ... requirements as
available. Going forward, PG&E is trying to ... 1547 ... IEEE ... the
penetration and ... 1541 ... IEEE certification test procedures to accommodate ... mu
my opinion, the ... 1547 ... IEEE designed for low penetration scenarios
penetration levels expected in California

I will have to defer to William Chung, whose GIS group mana
actual number of DTT required on ... projects ... 3 MW ...
review all of the interconnection ... studies ... may take more
time. Thanks.

Chase

June 21, 2012

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Thanks again Chase, this is helpful. However, could you further clarify how often DTTs are required on the transmission side for DG projects? We're hearing from some developers that these are being required by PG&E for DG projects, but if it's a rare event we can probably drop the issue. If it's fairly common, it becomes an important issue from the perspective of SB 32 eligibility.

Hopefully you or Will can get back to us quickly on this. Thanks,

Tam Hunt, Policy Advisor and Attorney
Clean Coalition
(805) 214-6150

June 22, 2012

Tam,

As penetration levels get higher we are starting to see many backfeed
cases generation is being highly installed lightly loaded rural areas of the Central
much to produce a backfeed onto the transmission backfeeds we apply
remote transmission line terminals feeding typically the we substations entire
tripping for faults on the transmission line, it's PG&E policy that
transmission line and trip via the generator relays or DTT will
tripping. Recognizing this may become of an issue as DG development
to look at various options, such as wireless DTT and allowing
given line section depending on the line configuration.

I can provide more information when back in the office on Monday.

Thanks

Mike Jensen

Supervising Engineer System Protection
Office Internal 821-5442

Office External (559) 263-5442 쪮□m
Cell (559) 824-7990

June 22, 2012

Thanks Mike, this is helpful. It would be great if you can let us know the frequency of requiring DTTs on the distribution and transmission sides, because if this is generally required it becomes a problem for the new SB 32 program, but if its still relatively rare for transmission DTTs to be required for 3 MW and under projects we probably won't worry too much about it. 쮀□η

Sincerely,

Tam Hunt, Policy Advisor and Attorney
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