BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program	Rulemaking 11-05-005 (Filed May 5, 2011)

REPLY COMMENTS OF THE UTILITY REFORM NETWORK ON THE STAFF FEED IN TARIFF PROPOSAL FOR IMPLEMENTING SB 32 AND SBx2

TURN
THE UTILITY REFORM NETWORK
Lower bills. Livable planet.

Marcel Hawiger, Staff Attorney
Matthew Freedman, Staff Attorney

THE UTILITY REFORM NETWORK

115 Sansome Street, Suite 900
San Francisco, CA 94104
Phone: (415) 929-8876 ex. 311
Fax: (415) 929-1132
Email: marcel@turn.org

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Pursuant to the October 13 Ruling of ALJ DeAngelis, The Utility Reform Network (TURN) submits these reply comments concerning the "October 13, 2011 Renewable FIT Staff Proposal" ("Staff Proposal") and the other documents attached to the Ruling. TURN replies concerning only a few of the key provisions in dispute amongst parties.

Based on a review of the parties' comments,[1] TURN recommends that the Commission:

- Update prices by using the results of RAM auctions as long as the RAM program is active, and using monthly adjustments if the RAM program expires;
- Reject the proposed Locational Adder because there is no certainty that distribution investments will be avoided or deferred; Alternatively, the Commission should order utilities to provide a 'distributed generation credit' in their rate cases to ensure ratepayer benefits comparable to the costs associated with any locational adders;
- Reject the proposed Transmission Cost adder as entirely speculative;
- Reject any unilateral change in the FIT program cap as illegal;
- Change the Resource Adequacy (RA) counting rules to enable utilities to obtain credit for capacity purchased pursuant to the FIT contracts.

1. FiT Price

1.1. Using the RAM Clearing Price

[1] When citing to parties' opening comments on the Staff Proposal, TURN identifies the party's name and uses the term "opening comments." Other pleadings filed in this proceeding are identified by a short name and the date of filing.

While most parties found some fault in staff's pricing proposal, there also appears to be a weak consensus that using results of the RAM auction is an adequate means of establishing the "market price" required by § 399.20(d)(2).

TURN previously explained why the MPR is the price that reflects the legislative intent of both SB 32 and SBx2. These bills contained language which was previously relied upon by the Commission as the basis for adopting the MPR.[2] TURN will not reiterate our position in these comments.

Several parties continue to advocate for technology or resource-specific prices.[3] The Sierra Club argues that resource-specific feed-in tariffs are consistent with FERC orders concerning avoided costs. However, even if such a proposal is permissible under federal law, the Commission cannot enact a tariff that is flatly inconsistent with state law. TURN previously explained why technology-specific administrative prices do not comport with the plain language, legislative intent and history of SB 32.[4] For example, the 4/14/2009 version of amended SB 32 directed the commission to "establish the cost of generation values and costs for each technology that is an eligible renewable energy resource." This section was subsequently *removed* from the final legislation based on an explicit legislative choice to reject technology-specific prices. In fact, TURN negotiated for the removal of this language in exchange for its support of the final bill.

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[2] See, especially, TURN/CCUE Opening Comments, July 21, 2011, p. 4-5.

[3] Sierra Club, p. 6-7; CEERT, p. 13-14. See, also, Staff Proposal, p. 3.

[4] See, TURN/CCUE Opening Comments, July 21, 2011, p. 5-6; TURN Reply Comments, Aug. 26, 2011, pp. 2-3, 6-8.

TURN does not believe that any party has rebutted our analysis and demonstrated that resource-specific prices are consistent with the legislative intent of SB 32. While CEERT very cogently summarizes the rules of statutory construction and explains the need to follow legislative intent to implement SB 32, CEERT and the other parties completely fail to rebut the evidence that multiple resource-specific FIT prices despite are simply inconsistent with the legislative intent of SB 32. Simply put, there is no evidence that the Legislature intended for the Commission to adopt a European-style Feed-in Tariff with resource-specific prices. Adopting this approach would represent legal error and place the entire program in jeopardy.

1.2. Price Adjustments Should be Connected to RAM Prices

Most parties support some type of automatic price adjustment on a quarterly or monthly basis. In our opening comments, TURN recommended an annual price adjustment based on an average of the two RAM auction results. Upon further evaluation, TURN agrees with PG&E that the price should be adjusted based on the results of each RAM solicitation.

Such an adjustment provides the surest means for FIT prices to reflect the actual avoided costs of RAM procurement. It provides the least potential for gaming in case RAM and FIT prices diverge significantly.

If the RAM program sunsets after four solicitations and the FIT cap has not been reached, TURN would support establishing monthly subscription goals and monthly price adjustments, as proposed by SCE. Monthly adjustments will better align FIT prices with market conditions. Quarterly adjustments may not adequately track market price changes.

2. The Locational Adder for Avoided Distribution Costs is Deficient, or at a Minimum Should be Implemented Only with an Explicit Credit Applied In Utility Rate Cases

Almost all the parties representing renewable developer interests comment favorably on the Staff Proposal to use the E3 methodology to pay a locational adder for projects in hot spot locations. These parties do not challenge any of the methodological assumptions. TURN is not aware of any of these parties providing a response to staff's question of how to "increase the probability that a distribution system upgrade will be deferred."

In contrast, the three IOUs severely criticize the methodology on both substantive and procedural grounds. TURN agrees with many of those criticisms. There are several compelling arguments that warrant rejecting the proposed locational adder, or at a minimum setting a process that will allow a far more detailed review of the methodology. TURN first highlights those arguments. Subsequently, TURN recommends a modified proposal in case the Commission chooses to authorize some type of locational adder to the FIT price.

2.1. Substantive Problems with the E3 Methodology

The E3 methodology does not account for the lack of 'dependability' of DG output, one of the three criteria required in D.03-02-068, overstates the peak output impacts of solar PV on circuit load, and ignores the Commission's policy precedent concerning payment for avoided distribution investments.

Both PG&E and SCE highlight the problem of DG "dependability," or the physical assurance that DG output will be available during peak load conditions.[5] SCE explains that it cannot defer or avoid planned distribution circuit upgrades resulting from load growth forecasts because output during peak times from distributed generation is not dependable. The prime example is the potential reduction in solar PV output upon sudden cloudiness. If solar PV output decreases during a hot summer afternoon due to weather, peak load could spike to the levels forecast *prior* to the reductions based on expected PV generation.

TURN appreciates that solar generators may reply that a) the potential for cloudiness is low on hot afternoons experiencing peak load conditions, and b) the geographic variability of DG output mitigates local weather patterns. The first point is sadly not true. The CSI Impact Report explains that the difference in output of CSI systems in PG&E and SCE territories on the day of the 2010 system peak reflected was caused by "cloudy weather conditions in the Southern California region."[6] The second point is probably not true at the circuit level. TURN agrees that studies indicate that having multiple dispersed sources of intermittent generation greatly reduces the impacts of variable output from any

[5] PG&E Opening Comments, p. 17-18; SCE Opening Comments, p. 15.
[6] CSI 2010 Impact Evaluation, Itron, Inc., June 24, 2011, p. 6-9.

individual generator or local cluster. However, the problem is that here we are dealing with very local conditions at the distribution substation and circuit level.[7] SCE has about over 4300 circuits, and some of them are probably quite short (on the order of hundreds of feet). TURN does not know of any studies addressing PV output variability at this geographic scale. We are concerned that the IOUs' position regarding the dependability of solar output at the circuit level may be valid.

Furthermore, SCE appropriately points out that the E3 method greatly overstates the load reduction benefits of PV output by assuming the entire capacity is available at peak.[8] SCE cites to the results of the most recent CSI Impact Report to substantiate the analysis that only about 1/6th of solar output is available at actual system peak. This result partially reflects the impacts late-peaking residential load, as discussed in TURN's opening comments.[9] Thus, any locational adder should be significantly reduced to account for the different timing of solar PV output versus circuit load.

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[7] For example, SCE's Distribution Substation Plan involves primarily adding transformer banks to existing distribution substations and adding 12 kV distribution circuits. SCE's Subtransmission Lines Plan involves primarily reconductoring existing 66 kV and 115 kV transmission lines and adding transformer banks to subtransmission substations. SCE forecasts spending approximately $735 million on such projects in 2010-2014. See, A.10-11-015, SCE-3, v. 3 (Woods, SCE). Capital expenditures on *new circuits* due to customer growth *cannot be avoided* by DG installations. One of the most significant unknown factual issues is the exact nature of capital investments used by E3 in its model.

[8] SCE Opening Comments, p. 16.

[9] TURN Opening Comments, p. 6-7.

TURN also fully agrees with the legal analysis of PG&E concerning the precedents established in D.03-02-068 and D.09-08-026. The Commission in D.09-08-026 adopted a value for avoided T&D investments based on an E3 model for the purpose of quantifying the "collective T&D investment deferral benefits of DG in an effort to analyze the net costs and benefits of our DG programs."[10] But the Commission explicitly stated that it was not appropriate to use a generic T&D value for "specific projects" or contracts between utilities and DG providers. The Commission reiterated that the T&D deferral benefits of specific projects or contracts should continue to be evaluated using the criteria enunciated in D.03-02-068, including the requirements "that the facility be operating in time for the utility to avoid system expansion, that it must be of a size that serves the utility's planning needs, and that it provide a 'physical assurance' that the customer will not ever require the utility service that would have otherwise been provided over the deferred investment."[11] The evidence to date indicates that there is no "physical assurance" that the full amount of installed DG capacity on a circuit will offset an equivalent amount of load and thus avoid distribution upgrades on that circuit.

From a process standpoint, *if* the Commission seeks to adopt some type of locational adder that is not project-specific, then TURN agrees with PG&E and SCE that the Commission should provide for testimony and hearings to address

[10] D.09-08-026, Sec. 5.3, p. 33-34.
[11] *Id.* p. 32.

the significant factual issues in dispute concerning the E3 model and its conclusions.

2.2. If the Commission Authorizes Some Type of Locational Adder, it Should Order the Utilities to Provide a "Distributed Generation Credit" in their Rate Cases

Nevertheless, *if* the Commission chooses to adopt some locational adder – whether based on the E3 method or some other analysis – the Commission *must ensure* that there really is an *avoided cost*. The E3 methodology presumes that utility distribution capital spending will be deferred and that ratepayers will save an amount equivalent to the locational adder payments. In response, PG&E states that the Commission "cannot ensure" that distribution system upgrades are actually deferred in utility rate cases.[12]

In our opening comments on this issue, TURN recommended additional study to determine a proper "feedback loop" that would result in reduced capital forecasts in utility rate cases. Upon review of the utility opening comments, we are pessimistic that such a 'feedback' can ever operate successfully in practice. Thus, *if* the Commission authorizes some type of locational adder (which we strongly oppose), the Commission should require the utilities to include a "distributed generation credit" as a direct offset to the "load growth" capital spending forecast in the utility's general rate case. The credit should be

[12] PG&E Opening Comments, p. 37.

calculated for each rate case by summing the amounts paid for locational adders to projects in the IOU service territory over the past three years and converting the levelized cost to an installed capital cost using the method in the E3 model.

Only by incorporating such an explicit credit can the Commission ensure that the price *actually paid* to projects obtaining a 'locational adder' results in actual avoided costs. Otherwise the adder will violate avoided cost principles and the ratepayer indifference standard. Ratepayers would pay developers a large additional payment for ten to twenty years without any certainty (or even a likelihood) that those actual payments would be offset by any commensurate savings in utility capital spending.

2.3. All Distribution Customers Should Pay the Locational Adder

PG&E explains that all customers benefit from any avoided transmission cost and should pay the Transmission Cost component of the FIT price. The same applies to any potential locational adder based on assumed distribution capacity investment deferrals benefits. Therefore, all costs associated with any locational adder should be paid via distribution rates so that all customers (including DA and CCA) share both the costs of the adder and the savings (if any) resulting from deferred distribution system investments.

3. Transmission Cost Adder to RAM Price

Staff proposed to augment the FIT price with a forecast cost of network upgrades for the one RAM project that sets the market clearing price. In our opening comments, TURN argued that it is inappropriate to force ratepayers to pay for this very speculative adder used to evaluate the costs of different projects. The utilities advances several arguments against the proposed "transmission adder" component of the FIT price. The IOUs note that there is no rational method for adjusting the results of the Phase I or System Impact Study results for one individual RAM project to provide a realistic estimate of network upgrade costs. No other party provided any reasonable response to Staff's Question No. 2.

After reading the opening comments, TURN is even more strongly convinced that this staff recommendation is entirely arbitrary and would result in an unreasonable price that has no relationship to any actual avoided cost.

The forecast of network upgrade costs from a Phase I or SIS are used by the IOUs to rank projects. The utilities have used these numbers as the best forecast for purposes of selecting projects based on 'least cost' criteria. However, these forecast numbers are highly preliminary. There is nothing on the record in this proceeding concerning such forecasts. It is TURN's understanding the network upgrade cost forecasts change significantly from Phase 1 to Phase 2 to a final interconnection agreement. The initial cost forecasts may be highly speculative for some projects.

Moreover, network upgrade costs for RAM projects will vary significantly from project to project. These costs reflect primarily the locational choice of the project vis-à-vis the transmission system. There is absolutely no basis for assuming that the benefit of any avoided transmission upgrade from the one most expensive RAM project that sets the market clearing price in any way reflects some long-term "avoided cost" of all the FIT projects. For purposes of *actual contract payments for twenty years to every FIT participant*, there is absolutely no basis for assuming the proposed upgrade cost forecasts – based on costs of just one project - are an accurate estimate of avoided costs. The Commission should reject this proposed element of the FIT price. Alternatively, at the least the Commission should obtain additional evidence on this issue.

4. Program Cap and Counting Existing Projects

4.1. The Program Cap Is Statutorily Mandated

TURN did not address this issue in our opening comments. The Staff proposed that the entire program have a cap of 750 MW, and that projects already under contract pursuant to the AB 1969 feed-in tariff program count towards this cap. However, staff stated that the IOUs *could* increase the FIT program cap, but would have to evaluate the cost impacts to comply with the requirements of SBx2 as codified in § 399.15(c) and § 399.20(d).[13]

PG&E and SCE both argue that increasing the cap is precluded by law, though SCE does not disagree with Staff's position that the "IOUs" are in the

[13] Staff Proposal, October 13, 2011, p. 15-16.

best position to make such a determination.[14] Several other parties supported the staff position and argued that the cap could be lifted pursuant to the cost limitations for the RPS program as a whole.[15]

The parties which assume the program cap can be lifted are confusing two different issues – the FIT mandate to provide a "must-take" contract for qualifying generators and the RPS mandate to purchase 33% renewables subject to cost limitations. The suggestion that the FIT program cap can be increased if the total RPS cost cap is not reached ignores the explicit language of § 399.20(f) that creates *two separate conditions* governing the utility's must-take obligation.

AB 1969 and SB 32 created a *specific* must-take obligation that applies *only* until "either" the electrical corporation reaches its share of the statewide cap of 750 MW (§399.20(f)(1)) or exceeds the above-market cost cap pursuant to §399.15 (§399.20(f)(2)). Any argument that the FIT program cap can be "increased" as long as the RPS cost limit is not reached eviscerates the meaning of § 399.20(f). It conflicts with the plain meaning of the statute and is illegal. It is legally impermissible for the Commission to *require* the IOU to continue the must-take obligation beyond the program cap.

Obviously, the IOU can choose to sign a contract with any renewable generator pursuant to other RPS procurement mechanisms, irrespective of their size. Indeed, the RAM program already applies to generators above 1 MW. The

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[14] PG&E Comments, p. 27; SCE Comments, p. E-7 to E-8.

[15] For example, Sierra Club Comments, p. 16.

restrictions on total RPS procurement pursuant to § 399.15(c) include the costs of the FIT program. But the cap on the mandatory nature of the FIT program cannot be increased irrespective of the cost calculations for RPS procurement.

4.2. All Feed-in Tariff Projects Must Count Towards the Cap

As noted by staff, SB 32 modified the *existing* §399.20 feed-in tariff, which had been authorized pursuant to AB 1969. SB 32 increased the program cap from 500 MW to 750 MW and made other changes to the program. It did not create a new feed-in tariff program. There is absolutely no basis for inferring a legislative intent to create a new program that would not count the existing § 399.20 contracts towards the in creased program cap.

5. Resource Adequacy Credit

Staff requested comments on how to implement § 399.20(i), which states that the generating capacity of FIT generators "shall count toward the electrical corporation's resource adequacy requirements." SCE appears to argue that this requirement mandates that each FIT project complete the required ISO deliverability study and obtain full capacity deliverability status.[16] PG&E states that absent the full capacity deliverability status, the Commission could reduce the IOU RA obligation or reduce the FIT price.

TURN suggests that the Commission should pursue the first option suggested by PG&E and effectively count capacity procured under the FIT

[16] SCE Comments, p. A-5.

towards the utility's RA obligations. The most reasonable interpretation of §399.20(i) is that the Legislature intended the utility buyers to obtain the RA benefits of the transaction under a must-take contract. The Legislature did not intend for the sellers to be able to retain separate attributes or values of the capacity or energy. There is no reasonable basis to conclude that the Legislature meant this section to impose additional extremely costly and time-consuming obligations on small renewable generators.

TURN assumes that the vast majority of projects under 3 MW will be able to interconnect and effectively provide their full capacity output.[17] The Commission should effectively change the RA counting rules so that the capacity of FIT generators effectively counts towards the utility's RA obligation. This issue should be a priority in R.11-10-023.

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[17] The IOUs did not argue that FIT projects might fail the full capacity delivery requirement. The issue of providing full capacity output is a question of network transmission capacity and is entirely separate from the question of whether that output is timed to meet system peak in a way that warrants the locational adder, as discussed previously in these reply comments. In the event actual data indicate that FIT projects are interconnecting at the transmission or subtransmission level with significant question concerning full capacity deliverability, TURN would recommend that this issue be revisited in a timely manner.

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Respectfully submitted,

___________/S/___________

Marcel Hawiger
Matthew Freedman
Attorneys for
The Utility Reform Network
115 Sansome Street, Suite 900
San Francisco, CA 94104
Phone: 415-929-8876 x304
marcel@turn.org
matthew@turn.org

VERIFICATION

I, Marcel Hawiger, am an attorney of record for THE UTILITY REFORM NETWORK in this proceeding and am authorized to make this verification on the organization's behalf. The statements in the foregoing document are true of my own knowledge, except for those matters which are stated on information and belief, and as to those matters, I believe them to be true.

I am making this verification on TURN's behalf because, as an attorney in the proceeding, I have unique personal knowledge of certain facts stated in the foregoing document.

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

Executed on November 14, 2011, at San Francisco, California.

___________/S/___________

Marcel Hawiger
Staff Attorney