California Public Utilities Commission

Energy Division

Clean Coalition Comments on E3 Distributed Generation Analysis (R. 11-05-005)

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Clean Coalition responses to staff questions

1. E3 ran several penetration scenarios (DG up to 15% of peak substation load, up to 30% of peak substation load, and up to the minimum substation load at peak solar production). Which of these scenarios can be adequately run with substation data, and which would require significantly more load data (e.g circuit level load information for all circuits) to provide reasonable estimates?

In order to understand what is happening below the substation, some estimate of the feeder load profiles is necessary. Given the annual energy loads on the feeders, the substation load profile can be allocated proportionately to get a reasonable estimate of the feeder loads. In order to understand what the impacts are to the protection elements, it is necessary to use feeder loads in all scenarios; the feeders will have to be modeled separately if they cannot be included at the level of this model.

2. If substation level data is all that is available, can you recommend adjustments that would improve the accuracy of the scenarios? For example, for the no backflow case, DG is constrained so that DG output does not exceed the minimum substation load in any hour. One adjustment could be to constrain DG to some fraction of substation minimum load to reflect the non-coincidence of circuit minimum loads with substation minimum loads. If there are no quantitative adjustments, can you provide useful caveats to the interconnection potential estimates?

Review of existing studies or current data related to representative systems can provide typical results that are sufficient for accurate scenario estimates. The wide deployment of "smart" meters and other conventional data collection each provide detailed sub-hourly load data for a representative range of feeders.

The best results will come from information at the feeder level. If this information is not available, then the utility should be consulted to get estimates of the mix of residential, commercial and industrial loads in order to estimate the daily load profiles.

However, if the high level definition of "no backflow" is that the DG output does not flow up to the transmission system, then the analysis can make the simplifying assumption that exceeding circuit minimum load is not an issue because the energy can flow down another feeder. Then, the interconnection potential is only dependent on the coincident substation minimum load and the only caveat is that simplifying assumption.

3. How can the DG potential study incorporate transmission network level constraints?

A large proportion of transmission level constraints are associated with deliverability commitments and Resource Adequacy contracting and accounting. As DG deliverability is recognized and achieved, and as older systems with prior deliverability rights retire, these constraints will be partially alleviated. However, these are fundamentally contractual, not technical constraints, and as such should be evaluated separately from the technical study of DG potential. DG will likely only be able to achieve full capacity deliverability on a broader basis when both the technical and contractual constraints are mitigated.

Theoretically, for DG that stays within the "no backflow" criteria, there should be no transmission network level constraints imposed on DG. In practice, DG appears to be constrained by the inability to ride through transmission faults and whether the transmission grid can supply reactive power to the local area. However, discussions in the IEEE 1547a and Rule 21 Advanced Inverter Working Group have focused on being able to ride through transmission faults as they impact the distribution grid. And the ability of DG with advanced inverters provide reactive power in the distribution grid has been viewed as a benefit, not a constraint. Thus, the DG potential study should assume that these constraints are not present.

a. Are there data available on the MWs of DG that can be interconnected before triggering higher voltage transmission and distribution upgrades?

DG and Smart Grid techniques are normally seen as delaying or replacing distribution upgrades. Distribution grids may require adjustments or replacements of protective elements if they are not compatible with potential backfeeding scenarios, but that has to be determined at the feeder level. There are no simple rules-of-thumb regarding thresholds for triggering upgrades; each scenario is very different (see answer to 3.b).

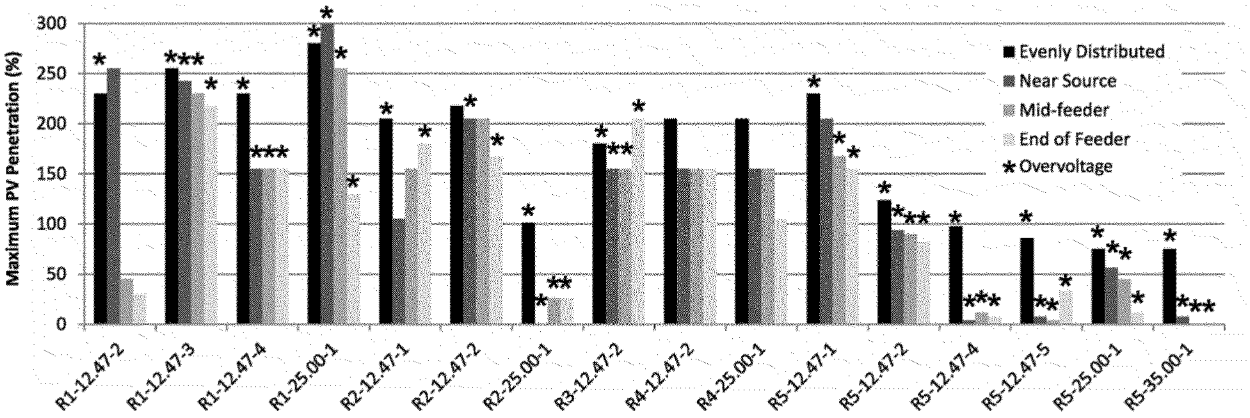
The most relevant data would be the interconnection study results for wholesale DG projects that have completed the utility WDAT or Rule 21 processes. In those studies, the utility engineers must have a methodology for determining when a new DG interconnection triggers upgrades such as transformer banks or Direct Transfer Trips.

b. How would one determine the locations where placing DG would minimize the negative impact on the transmission and distribution system from both a reliability and resource adequacy perspective?

There is no substitute for detailed modeling at the feeder level to answer this question. A study of PV penetration in feeders[1] showed that the steady state limits on PV penetration vary dramatically by the location of the PV along the feeder. This type of question can only be answered by modeling the distribution grid in each case.

The IEEE study used 16 different representative IEEE feeder models and scenarios of locating the DG at different points along the feeders (evenly, near source, mid feeder, end of feeder). They increased penetration until either an overvoltage or overcurrent event caused an issue. Figure 5 summarizes the results by feeder model and location of the PV; the widely varying percentages are a result of differing topologies and load profiles. It shows that there is no simple answer or rule-of-thumb to penetration questions; the scenarios must be modeled on their specific circuits at the feeder level.

[1] Steady-State Analysis of Maximum Photovoltaic Penetration Levels on Typical Distribution Feeders, Anderson Hoke, et al., IEEE Transactions on Sustainable Energy, Vol. 4, No. 2, April 2013.



c. Do you have other recommendations on data and methods to identify DG imposed transmission network deficiencies and the costs to correct those deficiencies?

It should be recognized that DG reduces the need for loads to be served by the transmission system, thereby reducing the energy delivered via transmission and the total transmission capacity required to meet demand. The wider voltage and frequency ride-through settings proposed in IEEE 1547a will help to solve problems related to low voltage and low frequency by allowing generation resources to remain attached to the grid much longer during a system event.

The first step is to provide a more accurate assessment of the benefits that DG can provide to the grid. A recent presentation by the CPUC at a SONGS workshop[2] shows how the CPUC is undervaluing the operational benefits of DG sources. The chart below from that presentation shows low annual capacity for Demand Response, no reactive power from Solar, and "maybe" reactive power from Energy Storage. At the same time, the CEC is sponsoring a working group on advanced inverters to accelerate the pace at which changes to IEEE 1547a, allowing reactive power from advanced inverters attached to the grid, can be implemented more quickly by changes to Rule 21.

[2] CPUC presentation, CEC /CPUC Workshop, July 15, 2013.

Type	Annual Capacity Factor	Expected Availability On-Peak	Dispatchable	Inertia	Reactive power support (VARS)	GHG-free
Energy Efficiency[1]	Reduces total energy demand					Yes
Demand Response	Low [2]	100%	Yes	No	No	Yes
Combined Heat & Power	80%	100%	Maybe	Yes	Yes	No
Large Solar	24%	77%	No	No	No	Yes
Rooftop Solar	19%	45%	No	No	No	Yes
Wind	33%	30%	No	No	No [3]	Yes
Storage	N/A	100%	Yes	No	Maybe	Yes
Gas Peaker/CT	10%	100%	Yes	Yes	Yes	No
Gas Combined Cycle	65%	100%	Yes	Yes	Yes	No

[1] Energy efficiency is not traditionally measured as a capacity factor resource, and savings varies widely by application and use.

[2] Demand response programs generally have low capacity factors due to typical usage limits of 100 hours or less per year.

[3] Some renewable energy sources, notably wind, actually require additional VAR support.

Distributed generation with advanced inverters can inexpensively provide local reactive power, greatly enhancing grid resilience. Oversized inverters can draw power from the grid to convert to reactive power even when variable resources are not available. Distributed voltage control is far more effective and efficient than centralized voltage control because reactive power has far higher line losses than real power, and losses increase as the line is more heavily loaded. Further when a transmission path is lost, local reactive power does not need to travel along the remaining congested transmission paths.[3]

4. How can the DG potential study evaluate the value to ratepayers of avoided transmission upgrades associated with renewable DG developed on a portfolio level? For instance, if California were to adopt a 40% or 50% RPS requirement and were to direct 1,000 MW of renewable DG procurement in a particular area of the state, could this deployment of a portfolio of DG projects offset transmission upgrades? If so, how could that value be quantified and attributed to individual DG projects?

There are a number of ways that avoided transmission upgrades may accurately be quantified, which we discuss below.

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[3] "Local Dynamic Reactive Power for Correction of System Voltage Problems," Oak Ridge National Laboratory, September 2008

Energy efficiency standards undertaken in California over the past 40 years have had great impact, keeping average household electricity use level during a period in which both housing size and appliances have substantially increased, and which has seen 50% increases in household energy use in much of the rest of the nation. These energy savings in California have avoided the need for approximately three -dozen additional conventional power plants , and the concomitant transmission and distribution capacity required to deliver this energy to load. Cle arly, reducing the need for transmission -interconnected generation directly reduces the need for transmission facilities and the rapidly rising costs of new transmission facilities; these cost savings cannot be ignored. While it can be difficult to precise ly determine the degree of deferred transmission and associated cost savings directly caused by each instance of distributed generation or efficiency, the aggregate impact is clear, and should be proportionately assigned to each project that contributes to deferred or avoided transmission expenditures.

For example, t he Long Island Power Authority has recently proposed offering a 7¢/kWh premium to 40 MW of appropriately sited solar DG facilities to encourage locational capacity sufficient to avoid $84,000,000 in new transmission costs that would otherwise be incurred, resulting in a net savings of $60,000,000. LIPA's guidance states: "The rate will be a fixed price expressed in $/kWh to the nearest $0.0000 for 20 years applicable to all projects as determined by the bidding process defined below, plus a premium of $0.070 per kWh paid to projects connected to substations east of the Canal Substation on the South Fork of Long Island."[4]

As another example, Palo Alto Utilities conducted a study of the value of local solar relative to non -local energy in 2011 [5], including local capacity value and transmission costs, and reflected this value in its procurement offers.

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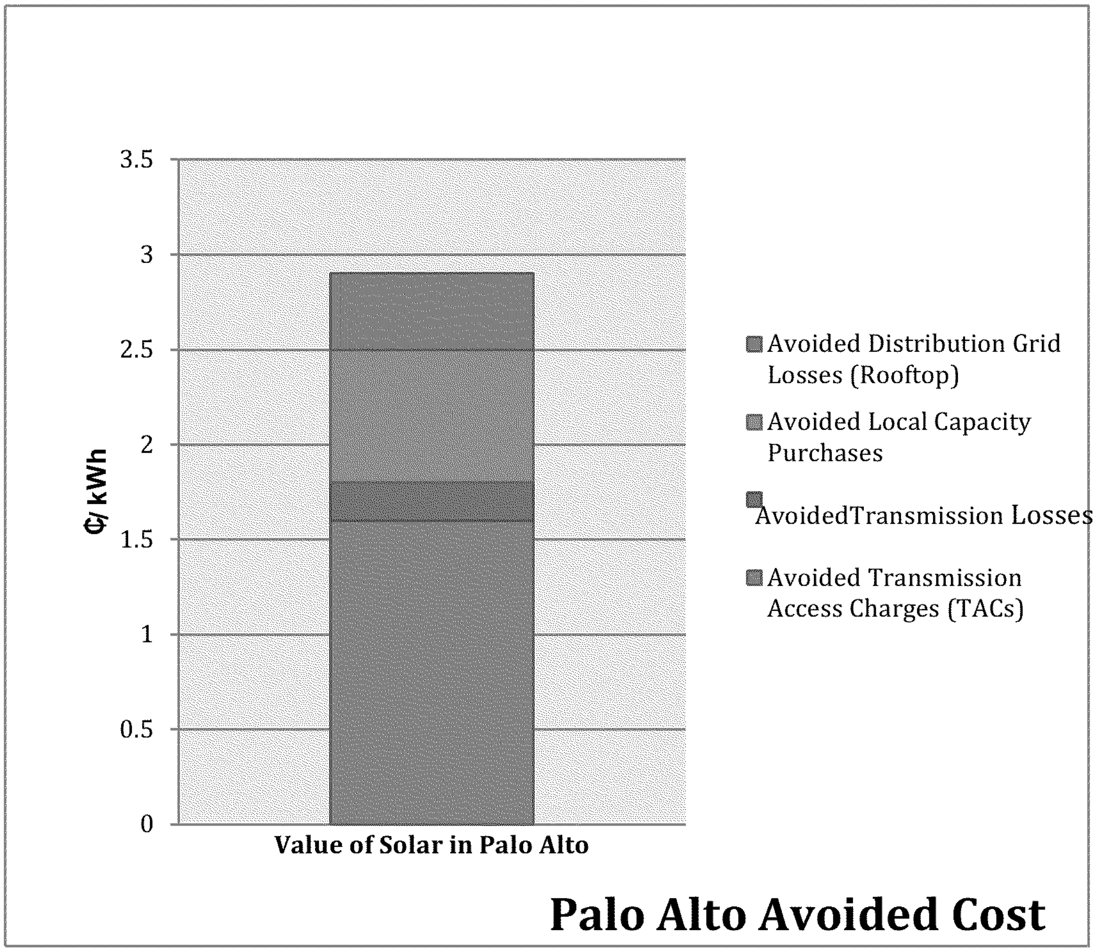
[4] Proposal Concerning Modifications to LIPA's Tariff for Electric Service, FIT070113 http://www.lipower.org/pdfs/company/tariff/proposals-FIT070113.pdf

[5] Renewable Feed-in Tariff Program Adoption Attachment E: Renewable FIT Program Pricing Methodology. City of Palo Alto, City Council Staff Report (ID # 2329) 12/12/2011. http://archive.cityofpaloalto.org/civica/filebank/blobdload.asp?BlobID=30132

Figure. 1. *Palo Alto Utilities avoided cost calculations.*

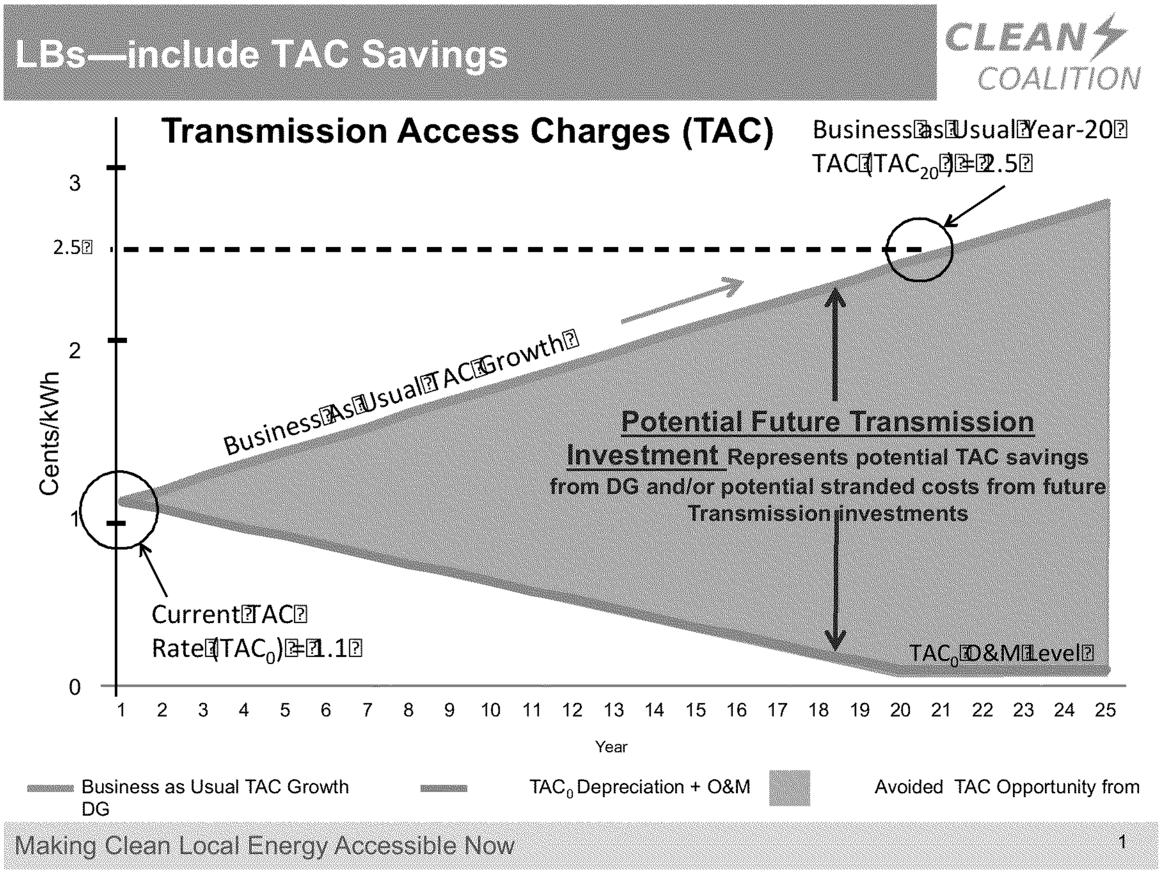


Last, in 2012 LADWP reached similar conclusions for its 100 MW CLEAN LA solar feed in tariff program. In both cases (Palo Alto and LADWP), DG serving local needs was valued at 3¢/kWh above the value of non-local sources, and this differential was reflected in prices offered.

A claim was made in the workshop that if the transmission required for the 33% RPS is already committed, adding DG will not avoid these transmission costs. However, this misses the critical point that reducing the use of this new transmission capacity allows every MW not utilized for energy now provided by DG to be available for other transmission requirements. Even with DG reducing the immediate need for transmission planned in conjunction with the 33% RPS, anticipated future increases in renewable generation, if not met entirely by DG, will make use of such transmission facilities. Meanwhile, the opportunity to defer construction until that time has very substantial value.

Likewise, to the degree that transmission planning is assumed to already include quantities of DG, it is sometimes claimed that any avoided transmission is already assumed and there are, therefore, no avoidable transmission costs to count in this study. This also is fundamentally flawed reasoning – avoided costs must include the cost of the alternative/default resource that would be incurred if the option under study were not used. If we don't deploy DG, we will need to provide all non-DG energy through transmission services – including both the Transmission Access Charges (TAC) cost per MWh (see Figure 2 and more information below), and the marginal cost of additional transmission capacity for each MWh not provided by DG. The DG included in transmission planning should be assigned the value of the transmission that would otherwise have been required. Even if grid operators can use existing capacity, we will in such cases be using up this existing capacity, and if this capacity is no longer available for other future needs, additional capacity will be required for those needs that would otherwise have been avoided/deferred.

Figure 2. *Clean Coalition estimate of TACs as a component of Locational Benefits.*



We provide the following additional information re transmission cost components:

- Transmission Access Charges (TACs, both HV and LV) are avoided by every MWh delivered directly to the distribution system by DG and serving loads on the same substation, and DG facilities will continue saving these charges as they increase over time for the entire operational life of the DG facility. While some have argued that TACs represent committed expenditures that will have to be paid in full regardless of whether DG incurs these charges, DG reduces the level of continuing investment required for transmission, directly resulting in lower TAC charges over time, as illustrated in the above TAC chart.
- Costs associated with operating and maintaining the transmission grid as well as profits to transmission owners.
- Line losses that occur as energy travels through the transmission grid.
- Congestion charges applied to energy sourced from constrained networks.

- Delays and uncertainty regarding the availability of new transmission facilities.
- Last, but not least, costs associated with building new transmission facilities – these costs should be calculated as the marginal cost of avoided new transmission, not the average cost of transmission; as such, recent cost examples, such as the Sunrise Power Link are appropriate. Note that transmission-interconnected projects do not reflect the cost of transmission upgrades in their energy prices because these costs are typically reimbursed by ratepayers, whereas all upgrades associated with wholesale distribution-interconnected projects are not reimbursed, and are therefore fully reflected in the PPA energy contract rates. The value of these infrastructure improvements from WDG should be considered as a benefit associated with locating generation on the distribution system, unless such upgrades solely benefit the triggering project and offer no additional or residual value to ratepayers.

Clean Coalition questions regarding the E3 report

The main references to transmission grid costs in the E3 report are in the section entitled Transmission Avoided Costs in Appendix C, but this refers to the "subtransmission system 'downstream' of the California ISO." We request that E3 clarify how this relates to the HV and LV transmission systems, and the differences in CAISO control of the LV system between SCE and PG&E, for instance, which determines where LV costs are accounted for.

Similarly, are systems covered by CAISO TACs included or excluded from the E3 analysis? For example: Costs associated with building new transmission facilities; costs associated with operating and maintaining ("O&M") the transmission grid as well as profits to transmission owners; congestion charges applied to energy sourced from constrained networks.

"Line Losses" in Appendix C references both Distribution and Transmission line losses, but it is unclear how the Transmission line losses factor into the LDPV analysis.

5. If the state continues to focus on 'easy to interconnect' locations without regard to locating renewable DG in favorable places on the distribution system:

a. What are the main attributes of an 'easy to interconnect' site?

The primary attribute for an 'easy to interconnect' site is that the new facility can be interconnected under Fast Track (Rule 21 or WDAT/WDT), which includes the supplemental review process that allows up to 100% minimum load.

However, we shouldn't eliminate the relatively simple interconnections available under non-Fast Track processes from the "easy to interconnect" category. The current trend at the CPUC is to define an interconnection cost threshold below which it is considered to be a "good" location or "strategically located". Since this dollar amount is based on the subjective whim of the interconnecting utility (and the study estimates can be off by large factors), a dollar threshold criterion for 'easy to interconnect' is fairly nonsensical.

Therefore, the state should develop a clear, physical definition of 'easy to interconnect' that is objective, rather than subjective, if further policy will focus and discriminate based on this categorization.

b. How could "easy to interconnect" sites be identified and DG promoted for those sites?

Fast Track-eligible sites should be readily identifiable by a survey of minimum load data for all distribution substations. We urge the Commission to include this survey in the final E3 report and to make this data publicly available through the IOU interconnection maps.

Non-Fast Track-eligible sites could be identifiable through the predictive model being developed currently in the Rule 21 reform proceeding (R.11-09-011). The Clean Coalition and IREC have proposed models for improving "cost certainty" in interconnection, focused on project attributes such as distance from substation, penetration level, and capacity of lines. These same attributes could help define 'easy to interconnect'. Data collection is ongoing in this proceeding and the Commission has not ruled yet on the preferred cost certainty model. However, the present proceeding should look to the Rule 21 reform proceeding for potential tools to these interconnection sites.

c. Are there any policy changes that you would recommend to facilitate faster interconnection?

The Clean Coalition has been active for four years in interconnection reform. While some improvements have been made to the Rule 21 interconnection process, much work remains to be done. The following are the major areas requiring significant further reform, most of which were specified in the Phase I Settlement joined by all parties and approved by the Commission in D.12-09-018:

1. Telemetry/other metering requirements.
2. Reconsideration of technical limits within Rule 21: Fast Track size limits, 15% screen, development of further objective criteria.
3. Cost allocation and certainty issues, including but not limited to: earlier cost certainty, standardized interconnection charges, 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 avoiding triggered upgrades, development of an online portal for applying for a Pre-Application Report. (Improved cost predictability and certainty of final costs established in the interconnection agreement are particularly important to reduce the number of projects entering the interconnection queue in order to determine costs. The majority of these projects ultimately withdraw, but only after time and resources have been devoted to studies, during which the queued capacity impacts all subsequent electrically related applicants.)
4. Study Deposits, pursuant to which the IOUs shall collect and provide data on the actual cost of system impact studies and facilities studies.

5. The Distribution Group Study Process [this should be completed soon in R.11-09-011]
6. Reconsideration of timelines, timeline compliance, and timeline remedies in the Revised Rule 21 Tariff (focusing on utility accountability and transparent, expedited recourse for developers when utilities are not adhering to the tariff).

An additional issue that has come up since the settlement is establishing the use of third party contractors to provide cost estimates and perform the construction of interconnection facilities. Based on the latest market feedback, ensuring that project developers can contract with a third party for construction of interconnection facilities could provide the single largest improvement in interconnection speed and costs.

6. If, instead, the state also worked towards targeting renewable DG where it can provide distribution system capacity benefits:

a. What would the implementation process look like? For example, how often would areas be reviewed to determine if they should be targeted, how much lead time would be necessary to allow DG implementation, how would the DG community be informed of the area need, how would equipment ordering be affected, how would insufficient DG be addressed, how would over or under participation be addressed?

The Clean Coalition has previously proposed legislation along these lines, though it has not been passed into law. An outline of our proposal is as follows and could be adopted, in whole or in part, by the Commission under its inherent authority independent of any legislative action:

- Each utility creates a D-Grid Development Plan that specifies planned D-Grid investments to maintain facilities, serve load growth, and prepare the infrastructure for high penetrations of distributed generation.
    - The Plan designates those areas in which deployment of new distributed generation would fit with the anticipated investments and mitigate future ratepayer costs.
    - The Plan is submitted with the triennial General Rate Case.
    - Each year the utility reports on the variance between actual investment and the Plan.

- The Commission opens a proceeding to determine the conditions under which D-Grid upgrades associated with new DG in the designated areas will be approved for cost recovery in rates.
    - The "interconnection facilities" costs, which are the costs of connecting from the DG facility to the nearest grid point, are always paid by the DG developer.

- Each utility designates the beneficial areas on their online grid maps that are already provided. In each designation, the map specifies the maximum new DG capacity that may be eligible for rate-basing of D-Grid upgrades.
    - Online maps will be updated on a quarterly basis to reflect any changes in deployed capacity in the areas.

Where a distribution system owner anticipates investment in replacement or upgrades of facilities that could be avoided through the addition of sufficient DG, such opportunities would be published and incentives or rebates offered proportional to but not exceeding the potential savings. The Long Island Power Authority (LIPA) recently announced a comparable program encouraging siting of facilities to avoid upgrades that would otherwise be required. LIPA stated in its recent materials: "The rate will be a fixed price expressed in $/kWh to the nearest $0.0000 for 20 years applicable to all projects as determined by the bidding process defined below, plus a premium of $0.070 per kWh paid to projects connected to substations east of the Canal Substation on the South Fork of Long Island."[6]

LIPA's premium rate offer is contingent upon sufficient capacity being committed to negate the need for upgrades (i.e. the incentive is only paid if more than x MW of projects are contracted to be deployed in the specified area). The LIPA model could and should be adapted for use here in California.

Responding to the sub-questions above that were not already answered:

How would equipment ordering be affected?

We can't offer much guidance at this time on this question. It seems that this will largely be up to each IOU to determine.

How would insufficient DG be addressed?

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[6] Proposal Concerning Modifications to LIPA's Tariff for Electric Service, FIT070113
http://www.lipower.org/pdfs/company/tariff/proposals-FIT070113.pdf

Under our proposal, each IOU would complete a D-Grid Upgrade Plan, which will describe the potential amounts of DG that could be developed in each resource area. The Commission would then authorize specific D-Grid upgrades for interconnecting these facilities, as they are required. Each major D-Grid upgrade would only be authorized once a certain threshold of interest is reached. This shouldn't require that project developers wait in a queue until the threshold is reached because this could likely subject developers to potentially long lag times in interconnection. Rather, developer interest should be considered indicated by existing projects in the interconnection queue and by a survey of developers expressing interest in the specific areas. Once the threshold is met, from a combination of queued projects and developer interest (from surveys), the IOU should be authorized to commence the specified D-Grid upgrades.

If the projected DG projects don't materialize, developers in the specified area would go through the normal interconnection process.

Essentially, the cost recovery option for pre-approved D-Grid upgrades will provide far more certainty for developers seeking to interconnect in approved areas. This will be a major advantage for both IOUs and developers because IOUs will enjoy the advantage of pre-approved rate-base and developers will enjoy the advantage of far higher cost certainty for interconnection.

How would over or under participation be addressed?

See our previous response.

b. What are the major hurdles and are these feasibly overcome?

The major hurdle for our plan will likely be utility support or lack thereof. We have engaged with the IOUs to varying degrees on the notion of rate-basing D-grid upgrades and have received a mixed response. Accordingly, we recommend that if the Commission pursues our suggestion, specified upgrades should be considered *prima facie* reasonable to ratebase as long as the upgrades at issue are specified in each IOU's D-Grid Upgrade Plan and approved by the Commission when the Plan is approved. As such, there should be no conflict in the IOU's General Rate Case with respect to this particular rate-base.

c. Could the potential lack of competition in targeted areas adversely affect program implementation or value?

Under our proposed plan there wouldn't be a lack of competition. Rather, once an upgrade area is announced, developers will know with certainty how many MW could be interconnected at no cost to the developers, and whatever procurement program is applicable will determine the level of competition. For projects in any specific area that exceed the planned upgrade capacity, normal interconnection procedures and costs would apply.

Distribution upgrade deferral

d. Do the utilities regularly consider distributed resource alternatives to their planned distribution capacity upgrades in the distribution planning process? If so, how does that process currently work?

We defer to the IOUs in responding to this question.

***e.* What reliability level does the whole system (renewable DG, distribution infrastructure) need to meet to defer an upgrade? Maintaining current reliability levels? Achieving equivalent reliability to a distribution upgrade?**

An upgrade should be deferred if required reliability levels can be maintained without the upgrade. Incentives to attract DG to avoid an upgrade, as with the LIPA model, should be based on the value of avoiding the upgrade relative to the cost and value of improvements that are achieved by added DG or upgrades. (This is similar to CAISO's current FERC Order 1000 initiative regarding non-transmission alternatives for potential transmission upgrades).

f. Utilities: How far in advance are significant (e.g.: >$5 million) distribution capital projects planned? When would you need assurance that an alternative is available in order to defer the project?

NA.

g. Developers: How long does it take to plan, construct, and bring a renewable DG project online in the best case and in your expected case?

From the Clean Coalition's interaction with developers of wholesale DG projects generally no larger than 5 MW, we offer the following estimates:

Best case

Activity	Time (calendar months)	Cumulative time (with some overlap)
Interconnection	6	6
Permitting	9	15
PPA	12	15
Construction	6	21
COD	1	22

Expected case

Activity	Time (calendar months)	Cumulative time (with some overlap)
Interconnection	12	12
Permitting	15	21
PPA	18	24
Construction	12	36
COD	1	37

h. Developers: If you had locational value information (low interconnection cost or distribution capacity value), how would this affect your development strategy? Based on the ranges presented in the workshop (e.g. $30/kW-year for PV and $50/kW-year for baseload), do you anticipate that these savings will be large enough compared to the cost of land or rooftop leases to impact

development decisions?

$30/kW-year is likely not large enough to impact development siting decisions since this translates to only 0.34 c/kWh. This would be a nice boost to project returns but not significant enough to be a major factor. However, previous research by E3 during the SB 32 implementation proceeding (R.11-05-005) found that locational value could be as high as 7 c/kWh in some locations. This conclusion was challenged by the IOUs and other parties but it suggests that actual locational value could be significantly higher than the $30/kW-yr that the E3 distributed PV report suggests.

Moreover, if the Commission adopts our D-Grid rate-basing proposal above, all costs of interconnection other than interconnection facilities would be rate-based, potentially reducing the cost of interconnection substantially for developers. Based on data received from IOUs in the Rule 21 reform proceeding (R.11-09-011), we know that average interconnection costs cluster around $250,000/MW for projects 20 MW and below. With solar DG costs coming down to as little as $2.5 million/MW in recent years, interconnection costs can easily represent 10% of the total project cost. If this 10% of total project cost is reduced or eliminated, it will certainly impact development siting decisions in a significant way – far more than would the $30/kW-yr suggested by the draft E3 distributed PV report.

i. Are there additional sources of data that could be used to determine the cost of interconnection for new projects?

As just mentioned, the IOUs have produced substantial data re interconnection costs in R.11-09-011, in response to discovery requests submitted by the Clean Coalition and our partners. The Clean Coalition has also submitted a motion to take formal notice of this data in R.11-09-011 and we urge the Commission to also take formal notice of this data in the present proceeding.

We also know that each utility keeps information on file for estimated unit costs for distribution grid upgrades – akin to the per unit cost guides that IOUs are required to make available for transmission upgrades. The distribution grid estimated unit costs are not public but each IOU uses these estimates to produce interconnection studies or Fast Track initial and supplemental reviews. The estimated costs are trued up upon completion of the specified upgrades and any difference between estimated and actual costs are charged to the interconnection customer upon completion. We suggest that the Commission request this data from the IOUs in order to have this data publicly available.

Telemetry and Controls

j. Utilities: What telemetry and/or controls can ease the interconnection process under current rules and practices? What telemetry and/or controls might be most helpful for interconnection in the future? If this varies by project size or renewable technology, please describe how.

Telemetry is required for full capacity deliverability so developers seeking deliverability will want to install telemetry when they interconnect. However, developers seeking "energy only" interconnection will view telemetry costs as an additional hurdle to interconnection and IOUs are currently charging as much as $65,000 for telemetry alone. We urge the Commission to examine these costs and to require IOUs to offer a third-party installation option for telemetry. Currently, IOUs have a blanket policy to deny third-party installations for required upgrades, citing safety and reliability concerns. However, safety and reliability concerns aren't as relevant with respect to telemetry equipment, so it seems that IOU concerns in this area should be mitigated enough to allow third parties to complete this work.

The value of telemetry data is closely proportional to the generating capacity of the facility reporting the data, and as such, investment in installation and operation of telemetry should be proportional. Since the benefits of telemetry accrue to, and are best evaluated by, the system operator, it is appropriate for the system operator to determine the level of telemetry appropriate for each facility, and to bear the cost of such telemetry if it is found to be warranted. Modeling, local forecasting, and statistical sampling can, however, provide an effective alternative to universal telemetry, especially when estimates are corrected and updated based on observation of actual response to system changes at whatever level of detail is available.

k. Developers: What telemetry and/or controls do you typically install on your projects? If this varies by project size or renewable technology, please describe how. If additional telemetry and/or controls could ease interconnection, is that a cost that you would likely accept?

7. Given the current CAISO process for evaluating local capacity zones, can we capture the impacts of local, non-dispatchable renewable DG in the assessment of capacity requirements? Is the answer different for 'behind the meter' systems versus merchant RDG?

To the degree that local capacity is based on observed (net) local load, the contribution of local DG is already reflected in the local and regional demand underlying evaluation of local capacity zones. Even without DG providing telemetry to provide for CAISO visibility, the impacts of all installed DG can be modeled with sufficient accuracy to support at least partial credit toward local capacity requirements.

8. What level of reliability must be met for local peak load reduction, or is there a 'Qualifying Capacity (QC)' methodology?

While the distribution system is typically a radial system, the deployment of multiple generation facilities on the same local line allows these facilities to achieve aggregated fleet reliability well above that provided by any individual facility. Where dozens of these facilities exist in a particular local area, reliability should be considered extremely high. However, the capacity provided by the largest facilities should be discounted from the aggregate since the loss of any one such facility would result in a commensurately reduced output. Likewise, the estimated variability in generation should be based on the fleet variability, not the variability of each contributor to the aggregated fleet.