Division of Ratepayer Advocates
California Public Utilities Commission

MEMORANDUM

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To : Adam Schultz, Energy Division Staff, adam.schultz@cpuc.ca.gov
cc: Service List R.11-05-005

From : Division of Ratepayer Advocates, Electricity Planning and Policy Branch,
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Subject : Responses of the Division of Ratepayer Advocates on
Renewable Distributed Generation (DG) Technical Potential Workshop Follow-up Questions

The Division of Ratepayer Advocates (DRA) submits these Responses on Renewable DG Technical Potential Workshop Follow-up Questions in accordance with an electronic mail received from Energy Division Staff, Adam Schultz, on July 3, 2013.

DRA applauds the Commission for holding the workshop on wholesale renewable distributed energy technical potential, and for giving stakeholders the opportunity to vet the methodologies and assumptions developed by E3 (Energy + Environmental Economics) for the study published by the Commission in March 2012 titled, "Technical Potential for Local Distributed PV in California." The workshop and study are essential steps to help develop an analytical framework for evaluating renewable DG technical potential and the associated costs and benefits.

DRA has organized these responses as a list of bullet points focusing on the questions posed by Energy Division staff and highlighting ideas and concerns following the workshop.

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?

The E3 report discussed three scenarios (DG capacity are 15% of peak substation demand, 30% of peak substation demand, and 100% of minimum substation demand) with one condition that there will be no power backflow to high voltage side of the substation. All of the scenarios can be adequately run with the substation data. However, in order to address the voltage and power protection coordination issues as discussed, more accurate circuit level demand information would be needed in order to facilitate a meaningful estimate. Existing voltage and protection data should also be part of the input to the study.

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 noncoincidence of circuit minimum loads with substation minimum loads. If there are no quantitative adjustments, can you provide useful caveats to the interconnection potential estimates?

If the constraint is to insure that DG output does not exceed the minimum substation load in any hour, then the DG capacity should be less than the 100% of the minimum substation demand.

If the constraint is to insure no back flow at the substation level, the DG capacity should be equal to or less than the substation minimum load. Adjusting down the DG to some fraction of substation minimum load level cannot ensure that there is no power back flow at the circuit level.

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

Currently, DG resources can be used to serve local load regardless of existing resource adequacy arrangement in the Power Purchase Agreements and existing power contracts to deliver generation located outside of the load pocket through transmission to serve the same local load. DRA supports the development of DG resources and other preferred resources to serve local load, which would minimize line losses and increase reliability. DG resources should be used first to serve local load. For example, DG resources should be accommodated first in distribution planning and transmission planning. In addition, DG resources should also be eligible as Resource Adequacy (RA) capacity in meeting the RA requirements for load serving entities (LSE). Failing to count DG resources towards meeting the LSEs' RA capacity obligation in meeting the local load needs does not make engineering sense since that could lead to excessive, costly, and unnecessary construction of transmission facilities to accommodate power delivery for generators located outside of the load pockets when this load can be met with local DG resources.

Any DG studies should be encouraged to incorporate transmission constraints. However with the constraints that there will be no power backflow to the transmission network, the DG scenarios should have minimal impact to the transmission network.

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

CAISO DG Deliverability study shows potential transmission upgrades in areas where DG will not receive capacity benefits. However, with the constraints that there will no power backflow from the distribution substation to the high voltage side of the distribution substation, there should be minimum need to upgrade the transmission network.

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?

The location of DG could introduce voltage and protection problems for the distribution system, but it is hard to imagine DG will create any problems to transmission systems.
DGs should be encouraged to be located near local loads. In this way, the DG output will supply the nearby demand, which would result in 1) power transmission from generators located farther away, 2) alleviation of existing transmission issues, and 3) reducing or obviating the need for proposed transmission projects.

More DG resources should also eliminate local RA need, because part of the demand will be served by the DG resources. In effect, IOUs should be required to procure less bulk generation to meet demand that is offset (served) by the DGs.

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

See DRA' response to Question #4.

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?

[Note: The report concluded that much of the identified technical potential for local distributed PV was in rooftop solar (presumably customer-side).[1] Inclusion of a higher RPS goal in the above example suggests that all or majority of the 1,000 MW would be expected to be 'system-side' DG, such that it counts toward the higher RPS goal. If this interpretation is incorrect or otherwise inaccurate, please specify any assumption(s) regarding what proportion of the 1,000 MW would be expected to come from customer-side DG.]

A portfolio of DG projects should be expected to help offset transmission upgrades and bulk generation investment. DG projects will also improve the reliability of the distribution system if they can meet certain performance requirements and the utilities can incorporate the DG development in their distribution planning and design. However, while DG might provide improved reliability, if the IOU distribution planners do not know how to study this benefit, they will continue to build distribution systems as if the DG does not exist. With the proper direction on location, DG should enable a deferral, if not avoidance, of specific transmission upgrade projects being considered to support demand growth. Note that transmission capacity will likely be reduced less than 1 to 1 for DG generation capability. For DG to reduce the need for transmission upgrades, the following are required:

- Advanced knowledge of the projected need for specific transmission upgrades, with sufficient notice to allow development of the required DG;
- Identification of distribution substations and feeders that would require load reduction to avoid the transmission upgrade;

[1] Technical Potential for Local Distributed Photovoltaics in California, Preliminary Assessment, by Energy and Environmental Economics, Inc., March 2012, pp. 6-8.

- Sufficient load on these feeders to allow DG build out without exceeding 100% of minimum load, **or**
- Distribution upgrades to accommodate backflow between feeders (this cost would reduce the benefit of the avoided transmission upgrade);
- Knowledge of the load profile of each feeder such that an effective load carrying capacity (ELCC) or equivalent could be calculated for a range of DG generator types. This would be used to define how much transmission capacity can be avoided for every MW of DG; and
- Monetization of the avoided cost benefit (e.g. a site-specific locational adder to a Re-MAT or other FiTs currently in place) to motivate investment in these distribution areas.

The value of such avoidance or deferral would be the avoided cost of the upgrade or the present value of deferring the upgrade. In this case, the CPUC should adopt a reasonable but transparent methodology for determining how much each DG unit contributes to reducing demand in that area. For example, some percentage of a unit's nameplate capacity can be counted on to contribute to serve local demand. The value of that unit would be its relative contribution to avoiding/deferring the transmission upgrade.

The avoided transmission cost could be quantified as follows:

- Start with an estimate of the cost of the transmission project to be avoided, per kW. The use of a proxy (e.g. Sunrise) as SDG&E used in its recent 'solar cost of service' study seems reasonable,[2] but adjustments should be made to the proxy price based on obvious differences in the location of the proposed transmission line, such as elevation gradients, population density, and electrical characteristics.
- Based on the distribution data from the response above, determine:
    - The capacity offset (e.g. kW DG required to offset each kW of capacity) for specific DG types for each feeder;
    - The allowable number of kW that can be added to each feeder without incurring distribution integration costs.
- The locational adder would be the avoided proxy cost per kW divided by the capacity offset (e.g. the $/watt for the transmission line avoided is reduced to reflect the proportion of DG production that coincides with the load profile of the feeder.)
- A DG compensation mechanism (e.g. Re-MAT or other FiTs currently in place) must be in place that has a placeholder for this adder.

It might not be necessary to set up DG MW goals in a particular area.[3] However, the CAISO DG Deliverability study is already expressing the amount of MW that can be installed in specific

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[2] Information regarding SDG&E's 'solar cost of service study' is accessible through the website of the Energy Policy Initiatives Center (EPIC), which is managing this project: http://www.sandiego.edu/epic/projects/?year=2012 (Accessed August 2, 2013).

[3] Note that Public Utilities Code §1002.3 already requires that "the [Commission] shall consider cost-effective alternatives to transmission facilities…including, but not limited to, demand-side alternatives such as targeted energy efficiency, ultraclean distributed generation,…and other demand reduction resources."

regions without triggering network upgrades. These provide a "first look" at what potential MW goals should be. To the extent the "no power backflow to transmission network" constraints as assumed by the E3 study is adopted, the Commission should require utilities to provide a DG potential (MW) report, with the necessary level of data granularity (temporal and spatial) in each local area of their service territories. This report can also guide DG developers in installing DG units in those areas. The IOUs' interconnection maps provide useful information regarding substation and feeder capacity, existing and queued DG, etc. Additional information (e.g., the likely cost of a transmission upgrade), however, should be included to enable DG developers and other stakeholders to observe areas where the IOU forecasts a need for distribution and/or transmission upgrades. Whatever the approach, to avoid excessive transmission build-out, *procedurally* the CAISO would need to incorporate the report in its transmission planning studies:

- CAISO local capacity studies produce one-year and five-year forecasts of local capacity deficiencies, assuming that approved and planned upgrades will occur in the five-year timeframe. CAISO should also incorporate reasonable assumptions about how much DG, DR and EE are likely to materialize during that same timeframe. CAISO should make these assumptions transparent to DG developers and demand-side program administrators (i.e. the IOUs) so that they can target those areas. The process should be iterative, such that past assumptions are refined based on actual experience.
- Assuming the above condition occurs, if CAISO's analysis still shows areas with deficiencies then it should assess how many more (MW of) preferred resources are available and whether it is sufficient to reliably avoid/defer the transmission upgrade, at lower cost.

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?

Generally, the main attribute of an 'easy to interconnect' site is typically where the DG is near the distribution substation, near the radial substation, or within a load pocket where zero or minimal network upgrades are necessary.

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

The IOUs are currently providing some useful information through their interconnection maps (as mentioned in response to Question 4); these maps should enable DG developers to choose the best areas and sites to develop DG, so as to minimize the cost to interconnect their projects. Work is ongoing in the Commission's distribution interconnection/Rule 21 proceeding (R.11-09-011) to facilitate DG interconnection. Stakeholders should continue to work through this proceeding to improve interconnection procedures for DG developers.

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?

In general, all demand side resources, including DG, should be considered with respect to distribution planning.[4] The Commission should require the IOUs to file annual distribution plans for approval and any distribution project proposals should be developed in alignment with the distribution plan. At a minimum, the total amount of revenue requirement associated with distribution upgrades should be aligned with and reflected in the distribution plan. The Commission should afford DRA, DG developers and other stakeholders the opportunity to review and comment on the IOUs' proposed distribution investment plans before the Commission approves them.

The process for avoiding transmission upgrades (outlined in response to Question 4) could be used, except that distribution upgrade costs would be considered rather than transmission costs. An additional adjustment would be required to prevent backflow from each feeder, or to include the cost of upgrading the existing distribution equipment to accommodate backflow.

- The determination of DG value should also be updated consistent with the frequency that the IOUs analyze/assess the need for distribution upgrades.
- The IOUs are in the best position to answer questions related to implementation, but their responses should be transparent and analyzed/ investigated critically. To the extent that resolving these issues is crucial to establishing a compensation method, the Commission should require a more robust record to consider the issues of how much lead time should be afforded, the most effective means of communicating necessary information, how to address over or under participation, and other important implementation details

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

An apparent hurdle is getting the right data from the IOUs, in the right format (i.e., feeder-level vs. substation level), to the right people (both internally, e.g. to customer programs staff, and externally, e.g. to planning agencies). The IOUs have primary responsibility over their own distribution planning processes and, to maintain flexibility, the CPUC has thus far refrained from micromanaging these processes.

However, the Commission should require the IOUs to make their local load growth assumptions and the data sources used for making those assumptions more transparent to stakeholders, so that stakeholders can evaluate whether those assumptions are reasonable. Furthermore, if provided with sufficient lead time, such information would enable DG developers and other stakeholders to target appropriate areas for demand reductions that would eliminate or delay the need for a distribution upgrade, at an equal or lower cost than the utility's cost of performing the upgrade. If demand reduction programs avoid or delay the need for distribution upgrades, utilities would not meet the ratemaking criteria of 'used and useful' and/or 'prudent investment' required to include such facilities (for unnecessary distribution upgrades) in rate base.

c. Could the potential lack of competition in targeted areas adversely affect program

[4] D.03-02-068 Ordering Paragraph 1 ordered all three electric IOUs to "ensure that their distribution planning processes incorporate SDG&E's distributed generation procurement approach to evaluate alternatives to distribution system upgrades." Also, Public Utilities Code §454.5(b)(9)(C) requires that "[t]he electrical corporation shall first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible."

implementation or value?

Lack of competition in areas where DG can provide the greatest system benefits could make it more difficult to achieve those goals.

A potential model for promoting DG and other distributed energy resources (DERs, aka 'non-wires' solutions, including energy efficiency, demand response and some types of storage) in targeted areas would be to solicit competitive bids for all DERs to provide the level of demand reductions needed to achieve the distribution benefit, at a cost equal to or lower than the utility's cost of performing the upgrade. As an example, Con Edison periodically issues solicitations for targeted demand-side management (DSM) entities to provide demand reductions that will enable the utility to avoid or defer a specific distribution upgrade.[5] To encourage competitive bids, the cost of performing the upgrade should be kept confidential. Subject to Commission and stakeholder review, the utility would select the optimal 'mix' of offers, accounting for the specific attributes of those resources.

If the solicitation failed to attract a sufficient amount of incremental resources, but some amount of potential DERs remained untapped in the targeted area, the determination of whether to proceed with the distribution upgrade should be informed by both the amount of the incremental cost posed by the DERs solution and a longer-term assessment of cost-effectiveness, accounting for important factors such as fuel diversity, risk management, state environmental goals and community values that (1) are in line with state energy policy preferences and (2) do not unreasonably shift costs to other ratepayers. For instance and more specifically, if a mix of demand-side resources can offset the need for a distribution upgrade but at a higher cost than their avoided cost value, consideration should be made for whether the area would be a likely candidate for microgrid development; over a longer timeframe, the cost of storage and other microgrid components may decline enough such that electricity can be supplied locally, at lower overall cost to ratepayers.

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?

The IOUs are best placed to respond to this question. DRA provides this response to make clear its position. In distribution planning, demand side resources should be considered the same as supply-side resources, with reasonable consideration for each resource's unique attributes. Data reflecting DG potential, applications, and online projects should be included with other inputs for distribution planning.

Distribution planning should also utilize advanced technologies in measurement, protection, control, and communications, which are the components of the Smart Grid, to facilitate the integration of distributed resources to the distribution system.

Distribution and home area network should be developed so that they will enable and not block possible implementation of rate structures, such as time-of-use and dynamic pricing that better reflect cost causation principles.

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[5] *Con Edison's Targeted Demand Side Management Program: Replacing Distribution Infrastructure with Load Reduction*, by Chris Gazze et al for 2010 ACEEE Summer Study on Energy Efficiency in Buildings.

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?
Different utilities have different reliability levels for many reasons, including geographic characteristics, customers served, history of the utility, age of the equipment, operation and maintenance practices, and safety culture. Unless an upgrade is needed to facilitate integration of renewable DG or prevent degradation in service reliability, utilities should not perform distribution upgrades.

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.[6]
Utility investments in Advanced Metering Initiative (AMI) provide hourly usage for each customer endpoint, and a secure two-way data communication system known as the "back haul" linking each customer with the utility IT systems. Utilities could analyze historic hourly usage data to determine load profiles on each feeder, and potentially to establish algorithms to provide near-real time feeder performance data. The back haul could be used to transmit inverter performance data to the utility. The AMI system has limited bandwidth so its ability to support DG is similarly limited, but IOUs should provide a detailed analysis of the capabilities and costs of using this sunk investment to support increased DG penetration.

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?
It will be very difficult to capture the impacts of local renewable DG in the assessment of capacity requirements without a fully detailed view of where that DG will appear on the transmission grid and whether that DG will be fully deliverable. This detailed view will require a deliverability assessment. Currently, the deliverability of DG will be evaluated by region through a CAISO stakeholder process.[7] According to the most recent DG deliverability study, there is a limited impact for DG in transmission-constrained regions without transmission upgrades.[8]

A number of ongoing proceedings seek to refine the value of DG for Resource Adequacy, including Track 3 of the RA proceeding (Rulemaking11-10-023) at the Commission and the Deliverability for Distributed Generation at the CAISO. DRA recommends that those proceedings are allowed to continue before the benefits of local RA are attributed to DG in cost-effectiveness evaluations because these proceeding/initiatives will provide results and information that can be used to evaluate local capacity zones, impacts of local, non-dispatchable renewable DG in the assessment of capacity requirements.

The answer is not different for behind the meter systems or merchant renewable distributed

[6] Questions 6f-k appear to be questions for utilities and developers since they seem to focus primarily on coordination of utility planning and project development. While DRA does not have specific responses for those questions, DRA offers these potential recommendations for Question 6j.
[7] http://www.caiso.com/informed/Pages/StakeholderProcesses/DeliverabilityforDistributedGeneration.aspx
[8] http://www.caiso.com/Documents/2013RevisedDeliverability-DistributedGenerationStudyResults.pdf

generation, unless the behind the meter systems are reflected in the CEC's load forecast, in which the capacity will be reduced inherently by reducing the load in the CAISO Local Capacity Technical study. The process to allocate net qualified capacity to individual DG resources seems administratively complex and should require significant time and effort to establish accurate protocols.

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

The Qualifying Capacity methodology requires an individual calculation for a net qualifying capacity ("NQC") for each power plant. In this way, each DG resource would require an NQC, which corresponds to what production the individual DG resources can deliver at the coincidental peak of CAISO's grid.

To determine the NQC for each DG resource, this requires a deliverability study in order to understand the congestion constraints and the correlation between output of the DG resource and all other resources in the region. As this type of study has not yet been developed, much work must be done to get to the point where DG can receive a NQC.