Renewable DG Technical Potential Workshop – Follow-up Questions

For general questions:
Adam.schultz@cpuc.ca.gov

Background:

Earlier in 2013, Energy Division staff held a workshop on wholesale renewable distributed energy technical potential. That workshop focused primarily on revisiting the methodologies and assumptions developed by consulting firm E3 (Energy + Environmental Economics) for the study published by the CPUC in March 2012 titled, *"Technical Potential for Local Distributed PV in California"*.

The purpose of that workshop was to give stakeholders the opportunity to vet the methodologies and assumptions developed by E3 for this study, with a particular emphasis on its quantification of the locational benefits of renewable DG. As explained by Energy Division staff at the workshop, staff expects to build upon the methodologies and assumptions deployed by E3 in this study to develop an analytical framework for evaluating renewable DG technical potential (for all technologies) and the associated costs and benefits. This framework is expected to be used to inform renewable procurement and long-term resource planning.

The slides presented at the workshop earlier this year can be found online here:
http://www.cpuc.ca.gov/NR/rdonlyres/5F2B76C0-043D-46CA-8C41-1F67E3116999/0/Jan31_CPUC_RenewableDGTechnicalPotentialWorkshopSlides.pdf

Purpose of Today's Follow-up Questions:

The questions below have been designed to provide parties with an opportunity to provide detailed written input that will be used to refine the methodologies and assumptions developed by E3 for this study, as presented at the workshop earlier this year. As stated at the workshop, this analysis is not designed or intended to be used to site individual projects; the analysis will be used to inform statewide planning and procurement.

As such, responses to these questions should reflect, as much as possible, real-world experience and should identify and quantify utility avoided-costs that can be realized. The following topics, among others, are out-of-scope: interconnection reform; the rules of the CPUC's DG programs; project-specific disputes; societal benefits.

Instructions and Standards of Review:

Please provide written responses via e-mail by no later than **5:00pm on Friday, August 9, 2013**. Written responses should be e-mailed directly to Adam Schultz, Energy Division staff, at adam.schultz@cpuc.ca.gov and should also be served on the e-mail distribution list for the CPUC's Rulemaking (R.) 11-05-005.

Also, please note, **parties should not file their responses on the docket**, as they would with formal comments filed within a proceeding.

The questions below are numbered. Please clearly mark your answers with the specific number of the question to which each component of your answer applies.

Standards of Review:

Proposed changes will be evaluated using the following standards of review:

(1) Does the proposed change or modification have a material impact on the model's output?;

(2) Have the proposed changes or modifications to the inputs or assumptions already been vetted, if possible, by the CPUC or a similar state agency?;

(3) If possible, is the data used to support the proposed change or modification sourced from a publicly available document?; and

(4) Do the costs reflect utility avoided costs – not avoided societal costs – and has the party demonstrated or explained how the value(s) can actually be realized?

[Questions begin on the following page]

Renewable DG Technical Potential Workshop: Follow-up Questions

DG Potential Study

The DG Potential Study focuses on estimating the maximum DG generation that can be connected to the utility systems. As described at the workshop, and documented in the prior study, E3 has estimated DG potential based on the impact of DG output on distribution substation loads[1]. Parties have commented, however, that DG can be limited by impacts on the distribution system segments downstream of the substation[2]. The following questions seek recommendations on how to improve the potential estimates.

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?**

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?**

The CAISO and the three large utilities have indicated the penetration of DG could also have adverse impacts upstream of the distribution system. The CAISO and the utilities are already dealing with transmission insufficiency in ensuring deliverability of existing and queued resources on higher voltage systems. The concern is that further interconnection of DG systems could add more deliverability problems that would lessen the resource adequacy (RA) value of non-DG resources, as well as reduce the value of DG resources seeking RA payments.

3. **How can the DG potential study incorporate transmission network level constraints?**
    a. **Are there data available on the MWs of DG that can be interconnected before triggering higher voltage transmission and distribution upgrades?**
    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?**
    c. **Do you have other recommendations on data and methods to identify DG imposed transmission network deficiencies and the costs to correct those deficiencies?**

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**

[1] http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf

[2] An eligibility screen for fast track interconnection of DG under Rule 21 specifies maximum qualifying fractions of load that may be interconnected for different technologies. These include 100% of minimum load, measured between 10am and 4pm for fixed PV, measured between 8am and 6pm for tracking PV, and measured over the entire day for all other technologies. This eligibility screen for fast track interconnection is applied at the 'point of interconnection'.

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?

Distribution Capacity Avoided Costs

For a number of policy reasons, California has a significant commitment to procure renewable DG. The best method for that procurement, however, remains under discussion. Two policy paths were presented at the workshop: (1) a path that would identify 'easy to interconnect' locations, where interconnection costs are lowest and projects can be completed the quickest; and (2) an alternative path where high value locations are identified and renewable DG projects are specifically targeted to those locations.

Both paths are designed to avoid the triggering of any major upgrades to the distribution system, but the second path aims to assist the distribution system by deferring the need for capacity investments that would otherwise be required if the targeted DG were not installed in the area. The second policy path offers the potential for additional utility cost savings, but requires tight integration between the distribution planning process and procurement of new resources. Based on the utility presentation at the workshop, it is unclear to what extent the additional distribution deferral benefits of the second path could be realized. The following questions seek stakeholder input on the two policy paths, with particular focus on the targeted DG path.

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?**
    b. **How could "easy to interconnect" sites be identified and DG promoted for those sites?**
    c. **Are there any policy changes that you would recommend to facilitate faster interconnection?**

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?**
    b. **What are the major hurdles and are these feasibly overcome?**
    c. **Could the potential lack of competition in targeted areas adversely affect program implementation or value?**

    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?**

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?**

Coordination of Utility Planning and Project Development

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?**

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?**

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?**

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

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.**

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?**

LCR Capacity Avoided Costs

In the workshop, the discussion highlighted the possibility that renewable DG located in local reliability zones could provide local capacity benefits. A possible advantage is that this locational value can be assigned on a larger regional scale based on the value of renewable DG in LCR zones without pinpointing specific locations on the distribution grid.

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?**

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