Renewable DG Technical Potential Workshop
Follow-up Questions

SDG&E Responses

I. DG Potential Study

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?

DG up to 15% of peak load is the scenario that can be adequately run with the substation data. This scenario is fairly conservative.

Additional circuit level data will be required in the determination of whether expensive interconnection distribution upgrades are required. This is why Rule 21 has filter screens to determine if the Fast Track route is feasible.

Question 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?

There are no quantitative adjustments that can be made to the scenarios to allow for interconnection of DG without additional engineering review. Factors such as project location, size, loading, and conductor rating can impact whether expensive distribution system upgrades would be needed.

Question 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?**

   An interconnection study is the only way to determine with a high level of certainty whether Distributed Generation can be interconnected without triggering transmission or distribution system upgrades. In a July 22, 2013 paper, Navigant has outlined a draft framework for studying the impacts of different levels of distributed generation additions. The framework contemplates discrete modeling of a few representative feeder circuits based on a statistically-based grouping of all distribution feeder circuits within a utility's distribution service area. SCE has conducted a similar study for its own distribution service area.[1]

---

[1] Southern California Edison, *The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System*, (May, 2012).

The CAISO has published results of a study which identified the amount of incremental Distributed Generation (in addition to renewable resource Distributed Generation included in the CPUC's 33% Renewable Portfolio Standard (RPS) portfolio) that could be connected at each substation within the CAISO Balancing Authority and be considered fully deliverable for Resource Adequacy (RA) counting purposes without the need for network transmission upgrades (beyond network transmission upgrades already approved by the CAISO).

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?

See SDG&E's response to question 3a.

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 SDG&E's response to question 3a.

Question 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?

To estimate the transmission costs avoided by increased levels of distributed generation, SDG&E recommends starting with the CAISO Board-approved 2012-2013 transmission plan and identifying the transmission upgrades approved in that plan that could theoretically be deferred or eliminated with increased levels of distributed generation. In many locations of the grid, SDG&E expects that increased levels of distributed generation deployment would have little or no impact on the need for currently approved transmission upgrades. (In other areas, increased levels of distributed generation could actually result in the need for transmission upgrades beyond what the CAISO has already included in its 2012-2013 transmission plan.)

As a practical matter, SDG&E believes it will be necessary to come up with a reasonable distribution of additional distributed generation across all substations within each utility's distribution service area. Given this distribution, transmission planning analysis could be used to confirm whether the identified transmission upgrades that could theoretically be deferred or eliminated, could -- based on the assumptions of analysis -- be deferred or eliminated.

By considering already-approved transmission upgrades, conclusions as to the value of deferred or eliminated transmission upgrades may be less speculative. SDG&E notes that the CAISO Board-approved 2012-2013 transmission plan contains cost estimates for the identified transmission upgrades.

II. Distribution Capacity Avoided Costs

Question 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?**

   For SDG&E's system: 1. renewable DG projects should be located on circuit feeder and two miles or less from the point of interconnection (POI). 2. The DG project is properly sized at equal or less than line section minimum load. 3. No project reverses power flow from the circuit to adjacent circuits or substation. 4. Impedance X/R ratio is greater than three (3). 5. Feeder size shall be 3/0 Al or greater. A combination of these factors may be necessary for 'easy' interconnection.

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

   Sites can be identified by use of the existing on-line maps (http://www.sdge.com/generation-interconnections/interconnection-information-and-map), pre-application reports and meeting with utilities in the review and discussion of the report.

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

   Procurement programs which currently exist for DG should have a component encouraging developers to propose projects near load centers. Also, there should be a process to ensure that queue spots near load centers are not tied up by projects that have a low probability of being constructed or coming on-line.

Question 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 existing SDG&E circuit feeder and substation area maps are available on the SDG&E website showing available generation capacity.

   The data in the Available Capacity Spreadsheet is updated every month and the map is updated every six months.

   SDG&E believes that to incorporate DG alternatives into the planning process would require a three year lead time. New processes would have to be developed on how to request alternative DG solicitation from developers to meet SDG&E future planning and DG engineering design and construction needs.

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

   Solar and wind DG are not available 7/24 and the planning engineer needs to provide for capacity needs whether the DG is in-service or not. Overcoming renewables that are not 7/24 is a challenge and is difficult to overcome at this time. Energy storage technology may help on a limited basis.

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

Lack of competition could adversely impact the value ratepayers receive if the program is not properly implemented. For example, if the program requires taking DG without regard to cost and there is a single project, lack of competition would lead to higher costs for ratepayers.

If DG is added regardless of whether lower cost options such as energy efficiency and demand response exist to address the problem, ratepayers receive less value. If the competition valuation process does not consider location on the circuit, size of project or other factors, ratepayers may receive less 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?

Yes, SDG&E considers DG resources as an alternative to capacity projects. The estimated cost of a DG project is compared to the capacity project and the amount of deferral time the DG project would provide before the planned project is required to be installed.

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?

A renewable DG project must meet equivalent reliability that a distribution upgrade project would add to the system. In addition, the DG must be located where the capacity is required on the feeder circuit or substation, installed and operational on time, properly sized to meet the capacity deficiency and provide appropriate physical assurance to ensure a real load reduction on the facilities where system expansion is deferred.

Coordination of Utility Planning and Project Development

f. <u>Utilities</u>: 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?

New Substation projects are typically planned with approximately 6 to 7 years lead time. For a substation transformer bank, typically 2 year lead time is required. For a new circuit or major re-conductoring project, a minimum of 2 year lead time is required.

Projects that require permits (land, city or county) may have additional increased lead times.

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

Not applicable to SDG&E

h. <u>Developers</u>: 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?

Not applicable to SDG&E

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

No renewable wholesale generation projects have yet interconnected to the SDG&E distribution system. SDG&E therefore does not have additional sources of data that could be used for new interconnection projects.

Telemetry and Controls

j. **<u>Utilities</u>: 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.**

SDG&E currently relies on telemetering equipment to provide real time information about the generator output in order to determine resource availability. SDG&E installs telemetering equipment on generators 1 MW and larger in compliance with Electric Rule 21. As communication systems progress, alternatives to telemetering equipment may become available in the future. As these alternatives to telemetering equipment are developed, commercialized, and become available, SDG&E will evaluate and implement them if they can more effectively provide the information currently provided by telemetering equipment.

k. **<u>Developers</u>: 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?**

Not applicable to SDG&E

<u>III. LCR Capacity Avoided Costs</u>

Question 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?

Non-dispatchable renewable DG that is assumed to be behind-the-load-meter has the effect of reducing peak demands within Local Capacity Requirement (LCR) areas and thereby the LCR that load serving entities are obligated to meet. Non-dispatchable renewable DG that is connected directly to the distribution system (wholesale DG) would count towards whatever LCR is established for load serving entities that have loads within the LCR area.

Note that the CAISO's "current process" for establishing LCRs and for counting dependable capacity towards whatever LCR is established, does not distinguish between dispatchable and non-dispatchable resources. Non-dispatchable Qualifying Facility and run-of-river hydro, for example, count towards LCRs just as dispatchable resources count towards LCRs. The fraction of the installed capacity that is determined to be dependable, however, does vary between technologies. Dependable wind generation capacity is usually a small fraction of the installed wind capacity while dependable gas turbine generation is usually at or near the installed gas turbine capacity.

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

The CAISO's "current methodology" for setting LCRs establishes the minimum amount of generation within a defined LCR area that is necessary to meet forecast one-year-in-ten peak loads within that area assuming this weather condition occurs at the same time as critical system outages (e.g., a G-1/N-1 or N-1-1 contingency event). Behind-the-load-meter distributed generation will appear as "local peak load reduction" based on the expected output of this distributed generation during the assumed one-year-in-ten weather condition. The CEC incorporates an aggregate "peak load reduction" estimate in its forecast of utility distribution service area loads. The CAISO's LCR modeling distributes this aggregate estimate to individual substations using historically-based load distribution factors.