Pacific Gas and Electric Company™

Claire E. Halbrook
State Agency Relations
Representative

77 Beale Street, B10C
San Francisco, CA 94105

(415) 973-0012
(415) 973-7226 Fax
cehu@pge.com

DOCKET
12-IEP-1D
DATE MAY 21 2012
RECD. MAY 21 2012

May 21, 2012

California Energy Commission
Dockets Office, MS-4
Re: Docket Number 12-IEP-1D
1516 Ninth Street
Sacramento, CA 95814-5512

**VIA E-MAIL**
**DOCKET@ENERGY.CA.GOV**

Re: 2012 Integrated Energy Policy Report/Renewables: Comments of Pacific Gas and Electric Company on the Interconnection of Renewable Projects in California

## I. INTRODUCTION

Pacific Gas and Electric Company ("PG&E") appreciates the opportunity to provide comments in the California Energy Commission's ("CEC") 2012 Integrated Energy Policy Report ("IEPR") Update on the interconnection of renewable projects in California. PG&E provides the following responses to the questions posed to each panel during the course of the May 14, 2012 workshop on this topic.

## II. SCENARIOS USED FOR TRANSMISSION PLANNING SHOULD REFLECT THE COMMERCIAL REALITY

**Question 1:** What uncertainties should be considered in the Resource Scenarios?

**Response:** The four Renewable Portfolio Standard ("RPS") Resource Scenarios ("scenarios") represent four potential end states in which projects with certain characteristics are preferred. The four scenarios currently before the California Independent System Operator ("CAISO") for consideration in the TPP are: cost-constrained, environment, commercial interest, and high Distributed Generation ("DG"). The differences between the scenarios represent various policy considerations, which may not reflect a project's ability to come on-line. In a letter dated May 16, 2012, The CEC and the California Public Utilities Commission ("CPUC") recommend that the CAISO, "use the 'commercial interest' scenario as the base case for the 2012-2013 TPP."[1] PG&E supports this recommendation and believes that this letter is a positive outcome of the stakeholder process. The cost-constrained or "least cost" scenario presents greater uncertainties than the commercial interest or "most likely" scenario. Using the cost-constrained rather than the commercial interest scenario could result in planning for projects that never come to fruition. Planning according to a scenario that does not provide adequate transmission may, in fact,

[1] CEC and CPUC to President and Chief Executive Officer Steve Berberich Letter. Re: Revised Base Case and Alternative Scenarios for CAISO 2012-2013 Transmission Planning Process May 16, 2012.

ultimately impose greater system costs and inefficiencies, no longer qualifying the cost-constrained scenario as the "least cost" portfolio.

Additionally, prudent planning would include room for contingencies, including what would happen in the following situations: a certain area fails to develop due to unforeseen environmental restrictions, further development occurs in areas of significant commercial interest, the resource potential associated with a certain area does not materialize, or more economic options become available in the future. By the time such information is made available, the opportunity to build the transmission to accommodate interconnection and integration of new replacement resources may have passed. PG&E believes that having a system with excess capacity could prove more economic than not having enough transmission because it provides alternative sources of generation when projects fail to come on-line.

A more coordinated approach to DG planning is also needed. PG&E sees great value in identifying optimal locations for DG so that planning can become more proactive. Ideal scenarios would take into account the energy profile of a particular area, interconnection capabilities in that location, and match with local load. Guidance from the state regarding balancing these factors to reach public policy goals is needed.

**Question 2:** How can we improve the renewable calculator model?

**Response:** PG&E offers the following potential improvements:

- The accuracy of the renewable calculator should be improved with respect to transmission cost scores and assumptions for delivery over existing lines in a variety of areas, including the following: the assignment of non-competitive renewable energy resources ("CREZ"), out-of-state resources, and DG.

- Greater weight should be given to projects that have been vetted through the procurement process (e.g., have an executed and/or approved power purchase agreement ("PPA") irrespective of having a permit in place). Policymakers should keep in mind that any project with an on-line date beyond 2017 will likely not have a completed permit application in place during the 2012 procurement process.

- Any adjustments to costs based on technology should be up to date and all technologies should be updated to the extent possible.

- To the extent possible, other cost considerations should be included (e.g., land costs).

- If updated information cannot be broadly applied, then that information should not be used to alter the costs or scores of a subset of resources without due consideration to its effects on the rest of the resources. Applying potentially inaccurate information could produce unexpected results.

**Question 3:** What policies or goals should be considered in the development of the scenarios? How should DG policies be reflected in the scenarios?

**Response 3:** If the scenarios are to be used as an input to the transmission planning process, then development of the scenarios should take into consideration meeting the 33% RPS goals, ensuring system reliability, and preserving optionality such that a robust and competitive market for renewables is enabled. The utilities should be consulted to create a methodology and study framework for developing DG inputs to the portfolios. This will yield more accurate and cost-effective results. To reliably integrate the renewable resources identified in the RPS scenarios, the transmission planning process should also clearly reflect the impact of the state's Once-Through-Cooling ("OTC") policy as well as operational needs such as spinning reserve requirements. Given the networked nature of the system, shutting down generation in key load areas can have a significant impact.

**Question 4:** How do we make the process work efficiently so that the identification and permitting of transmission in California facilitates the development of renewable generation?

**Response:** The comments made by Chris Ellison of Pathfinder/Zephyr during the workshop were compelling. Developing a plan to accommodate a wide range of possible build-out scenarios and permitting the most important or longest lead time projects before they receive authorization to build would be a significant development. This solution could alleviate the roadblock created by the transmission planning and local permitting processes. It might prove somewhat time and resource intensive to permit transmission that is ultimately never built, but this seems like a solution worth further consideration to preserve optionality.

**Question 5:** Are there incentives or penalties that can be incorporated into the procurement process that would encourage renewable generators to locate in desirable transmission areas?

**Response:** PG&E's RPS procurement programs, including the RPS Request for Offers ("RFO") Solicitation, prioritize offers that have the best combination of market value, viability, and qualifications. One of the inputs to this process is the project's viability score,[2] which gives preference to projects with certain characteristics, such as placement on disturbed land or simplified transmission interconnection requirements. Among the considerations of the least-cost-best-fit process is the evaluation of a project's estimated transmission costs.[3] Additionally, developers should be required to pay for any upgrades their project triggers. This will incent siting in more desirable locations.

Providing the market with information will play an integral role in making these incentives possible. The CAISO's Transmission Planning Process/Generation Interconnection Procedures ("TPP/GIP") Integration and Deliverability for DG initiative are expected to help provide the

---

[2] As directed by D.09-06-018, PG&E will use a modified version of the Project Viability Calculator (PVC) issued by the CPUC on June 5, 2009, as a screening tool. The Solicitation Protocol explains how the PG&E modified version of the adopted PVC will be used to evaluate bids, as ordered in D.09-06-018.

[3] PG&E's 2011 RPS RFO, see Attachment K. http://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/renewables2011/index.shtml

needed information. PG&E also already provides distribution system information through its photovoltaic ("PV") Program map application.[4]

Concerning financial incentives, PG&E believes that when DG reduces the need for transmission, this cost savings should be credited to the ratepayer as a deferred increase to the Transmission Access Charge ("TAC"), not in the form of a direct incentive to the developer's energy bid. PG&E is concerned that if the deferral for which a developer receives an incentive does not materialize, the customer will end up paying twice for the transmission, once to the developer through the incentive and a second time to build the transmission. Furthermore, the CAISO has suggested that DG does not reduce transmission infrastructure needs in all cases and can occasionally increase transmission requirements due to the networked nature of the transmission system.

**Question 6:** What information is needed by the stakeholders (Load Serving Entities, developers, regulators) to assist in decision making?

**Response:** From the load serving entity ("LSE") perspective, knowing the procurement product definitions, targets, and the framework or program under which the LSE will be procuring resources is critical for decision-making. PG&E would prefer that the procurement framework incorporate meeting policy goals in the most cost-effective manner for serving customers. Ensuring that the costs of various procurement options are as transparent and discernible as possible could be best achieved by attributing the cost responsibility for interconnection-related facilities to each generator whenever possible.

## III. PG&E HAS CONNECTED THOUSANDS OF MEGAWATTS THROUGH EXISTING PROCESSES AND HAS TAKEN STEPS TO RESPOND TO THE RECENT INCREASE IN REQUESTS

PG&E would like to clarify that there are three separate interconnection processes and acknowledge that the company has seen great success in connecting customers through these programs. Under the Rule 21 process for "system-side of the meter generation" (e.g., Public Utility Regulatory Policies Act or "PURPA" contracts), PG&E has seen a steady flow of requests, at approximately 50 per year. Under the Rule 21 process for "customer-side of the meter generation" (e.g., net energy metering and self-generation incentive program), PG&E has connected a total of 14,000 customers since the program began. These requests are typically processed in two to three days for systems averaging 6 kilowatts in size.

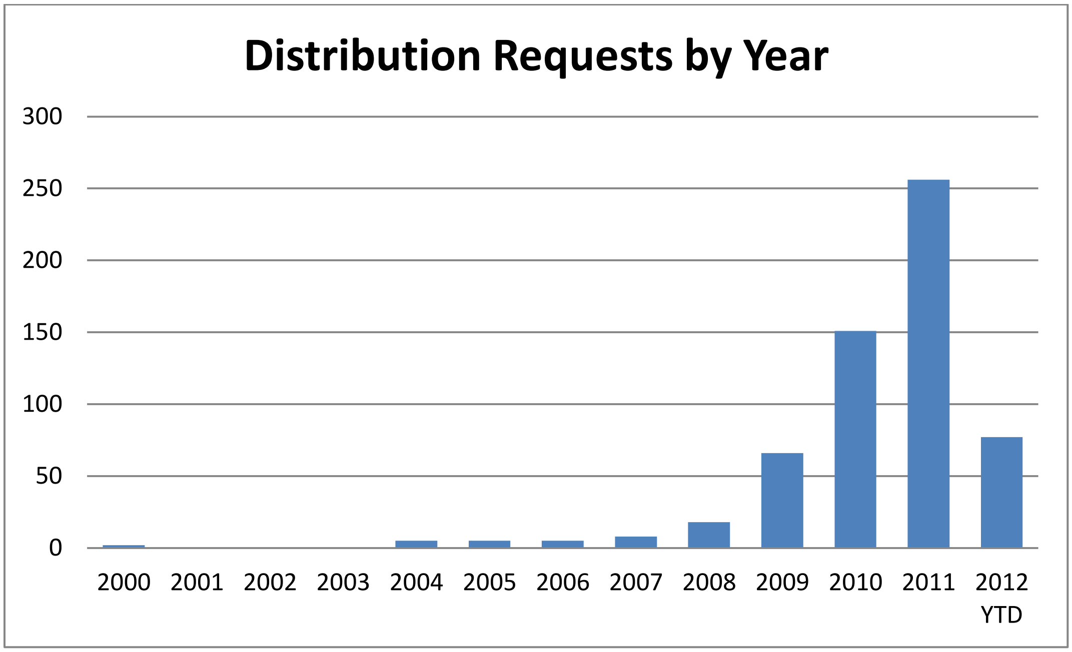
The responses to the questions below generally apply to the third interconnection process: the Wholesale Distribution Access Tariff ("WDAT") where the point of interconnection is the investor-owned utility ("IOU")-controlled distribution system.

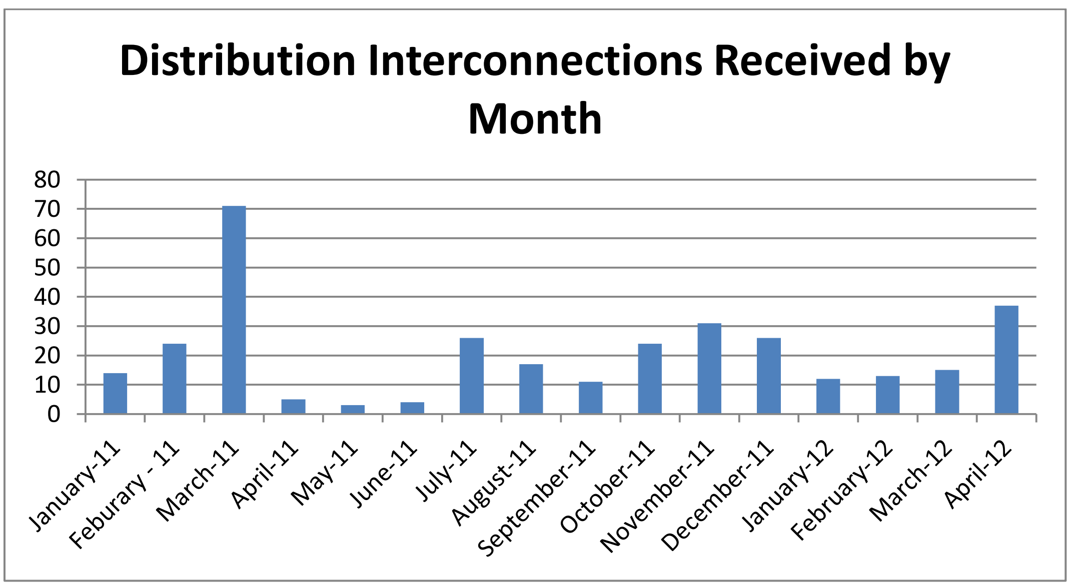
**Question 1:** In the past six months, has the pace of interconnection requests increased or become more manageable for utility engineers to process? Please explain.

[4] http://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/pvmap/

**Response:**

As the graph below indicates, the number of distribution-level interconnection requests has significantly increased in recent years.




**Question 2:** Have you added new staff to process and study increased interconnection requests? Have you added any new analytical tools and/or systems that will increase process efficiency and/or reduce the costs of interconnection studies?

**Response:** PG&E evaluated its interconnection process and as a result, made significant changes in the following areas:

- In response to the increased number of applications, PG&E increased staffing for the interconnection team. This includes an expansion of the Generation Interconnection Services Group and other technical partners within PG&E that conduct key studies. PG&E will continue to evaluate its resources and adjust them as demand fluctuates.

- PG&E's Distribution Planning department has transitioned from a custom distribution planning tool to CYME, a power engineering software which offers more robust analyses of the impact of added generation on the distribution system.

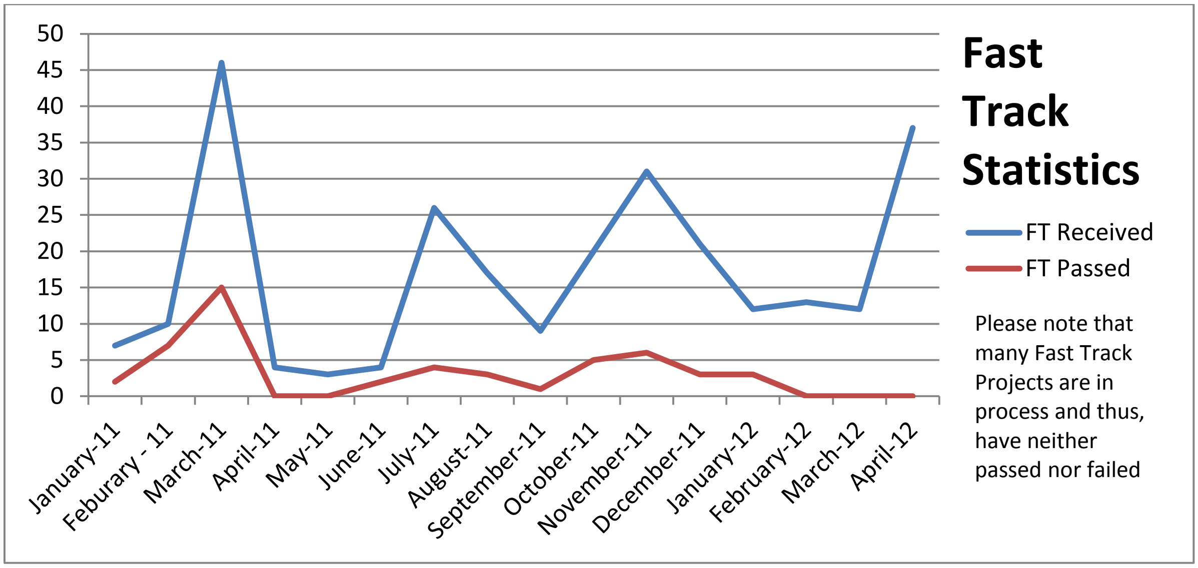
- PG&E's Generation Interconnection Services department is in the process of transitioning from a record depository database to a workflow management tool. This new tool will serve as a repository for records while also providing custom-built interconnection timelines and triggers. This new tool is intended to simplify the administrative process, increasing overall efficiency and reducing costs.

- PG&E is working to update its website and build an online application.

**Question 3:** What percentage of interconnection requests qualify for Fast Track interconnection? Developers complain that very few Fast Track interconnection requests are actually successful. In the past six months, has the success rate of these interconnections increased? Please explain.

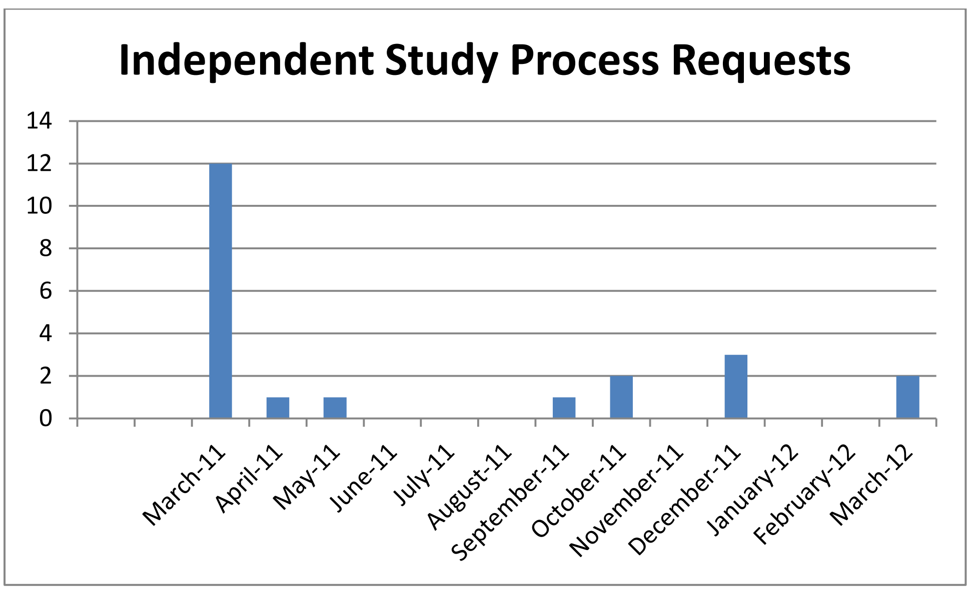
**Response:** The average Fast Track request is 1.4 megawatts ("MW") and the majority of these projects are sited in rural areas where the peak load is often quite low. Screen 2 of the Fast Track process requires that the generating facility, in aggregate with other generation, cannot exceed 15% of peak load. For this reason, the majority of these projects do not pass the Fast Track process. Roughly only 20% of interconnection requests pass. Historical results are shown in the graph below. Several workshop participants cited Screen 2 as the leading cause of Fast Track application failure. A section of the pending Rule 21 settlement would augment this process by allowing projects to undergo a supplemental review if their generation exceeds 15% of peak load. The supplemental review includes penetration, power quality, voltage, safety, and reliability tests. This additional pathway will hopefully allow more projects to be approved.

The average size of Fast Track requests is likely driven by the size limit of PG&E's current Feed-in Tariff program (1.5MW cap), which will soon increase to 3MW in accordance with Senate Bill 32. As a result, PG&E anticipates an increase in the average size of Fast Track requests. If the Rule 21 settlement is not approved, a potential dip in the number of successful projects could occur due to the 15% of peak load limitation combined with the increased size of proposed projects.




**Question 4:** Are requests for Independent Studies increasing? What percentage are successfully interconnected using this process?

**Response:** The number of Independent Study requests are documented in the graph below.




The Independent Study Process ("ISP") was introduced as a result of PG&E's GIP filing in March of 2011. Subseqent to the filing, PG&E began receiving interconnection requests for the ISP and is processing those applications. The ISP requires 6-9 months of interconnection studies followed by the negotiation of a contract and then the implementation of the project. Currently, projects either remain in the study phase or have withdrawn. These projects will likely begin interconnecting in late 2012 or early 2013.

**Question 5:** Has the cluster approach to studying interconnection requests resulted in more successful and timely interconnections? Has the pro rata approach to assessing infrastructure upgrade costs among project developers in the cluster resulted in more projects going forward and signing power purchase agreements?

**Response:** A small number of projects have requested interconnection in the Cluster Study Process. Similar to the ISP, PG&E began the Cluster Study Process in March of 2011. As a result of this limited sample size and timeline, it is premature to assess the results of this process.

**Question 6:** Concerning interconnection costs, what issues are most significant and should be dealt with first?

**Response:** For distribution, these costs are borne by developers. Cost uncertainty is certainly the most significant issue. Coordination prior to beginning the interconnection process will help alleviate this uncertainty. Use of the Renewable Auction Mechanism ("RAM") maps that PG&E provides on a semi-annual basis will also provide more certainty. PG&E is willing to meet with developers before they apply to help them identify optimal siting locations.

**Question 7:** Are there regions in the state with greater interconnections challenges?

**Response:** Kern and Fresno counties present the greatest interconnection challenge given the combination of abundant solar resources and availability of land in the region. These prime attributes lead to many interconnection requests in the area, which can potentially overwhelm local facilities and increase the associated interconnection costs. Additionally, many of these requests come from facilities in remote locations, away from substations, further increasing interconnection costs. Maintaining safety, power quality, and reliability while interconnecting generation into a system not originally designed to support these resources, represents a significant challenge.

## IV. THE IMPACT OF HIGH DG PENETRATION MUST BE FURTHER EXPLORED

**Question 1:** What changes need to continue to process interconnections and ensure system safety?

**Response:** Low DG penetration has little impact on the system, allowing for a simplified study process. High penetration with large units on the other hand, significantly increases the need to perform dynamic/stability studies similar to those conducted on the transmission system. Additionally, reliability concerns preclude trip schemes from being simplified under high DG scenarios. New computer programs and associated modeling may be needed to manage these new studies. Such studies will require more time and resources to perform.

**Question 2:** Over time, as the penetration increases, what issues may arise and what are potential solutions?

**Response:** As the level of penetration increases, the existing interconnection methodology employed for low penetration scenarios (existing Rule 21, UL-1741 and IEEE-1547) will no longer be adequate.

For example, existing voltage regulation equipment is designed to provide +/-5% voltage regulation throughout the entire feeder from zero load to full load. There may be multiple stages of voltage regulation on any given feeder. Each stage has 15-30 seconds of time delay in order to coordinate with the others. On some feeders, the entire regulation process may take over a minute to complete. The load diversity on any given feeder usually results in load changes gradually throughout the day. By contrast, the output of a PV installation on a local feeder may change abruptly from 100% to 20% and back to 100% in seconds. Hence, without mitigation, the addition of high PV penetration on a given feeder may lead to severe voltage fluctuation for other customers on the feeder.

A potential solution to these fluctuations lies in ensuring that generating facilities are compatible with the existing distribution system design. This will minimize the potential system impact. For example, if PV installations can be designed to slowly ramp their output up and down, the existing voltage regulation equipment will function properly, minimizing voltage fluctuation resulting from intermittent output. Most projects can already control the ramp up of energy production, but controlling the ramp down will require more advanced technologies, such as energy storage. This approach should simplify the interconnection of PV installations that do not cause significant reverse flow.

Another potential solution is to require dedicated collector feeders or taps to bring PV output directly to the substation. This will minimize voltage fluctuations associated with intermittency. Such an approach could also be used for large PV installations. PG&E is working to install dedicated feeders on our projects.

**Question 3:** What system modeling and analysis is underway that can inform the interconnection process/system operations issues?

**Response:** Currently, PG&E models generators and performs power flow studies under different loading conditions to identify loading and voltage issues. PG&E also performs fault studies to identify needed protection requirements and provide necessary relay settings. With high DG penetration and a large number of DG installations on any given feeder/area, the number of operational combination scenarios would be increased exponentially. This could trigger the need to develop an automated study process to manage power flow studies. PG&E is exploring this approach with our power flow program developer, CYME. Time is needed to develop this program and test new schemes.

## V. CONCLUSION

PG&E appreciates the opportunity to provide input on the interconnection of renewable projects in California. We look forward to participating in additional upcoming workshops. Should you have any questions about PG&E's comments, please do not hesitate to contact me.

Sincerely,

/s/

Claire E. Halbrook

cc: L. Green by email (lynette.green@energy.ca.gov)
H. Raitt by email (heather.raitt@energy.ca.gov)