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California Energy Commission
Dockets Office, MS-4
Re: Docket No. 11-IEP-1G, 11-IEP-1H
1516 Ninth Street
Sacramento, CA 95814-5512

Re: Docket No. 11-IEP-1G, 11-IEP-1H, Distribution Infrastructure and Smart Grid

Please find attached PG&E's comments on the June 22, 2011 Workshops on Distribution Infrastructure Challenges and Smart Grid Solutions to Advance 12,000 Megawatts of Distributed Generation. Should you have any questions or need additional information, please contact Valerie Winn at 415/973-3839

Sincerely,

Mark Krausse /VW/

Enclosure

PACIFIC GAS AND ELECTRIC COMPANY COMMENTS IN RESPONSE TO THE JUNE 22, 2011 IEPR WORKSHOP ON DISTRIBUTED INFRASTRUCTURE CHALLENGES AND SMART GRID SOLUTIONS TO ADVANCE 12,000 MEGAWATTS OF DISTRIBUTED GENERATION
DOCKET NO. 11-IEP-1G, 11-IEP-1H

Pacific Gas and Electric Company ('PG&E') appreciates the opportunity to comment in response to the Distributed Generation topics raised at the Integrated Energy Policy Report ('IEPR') workshop on June 22, 2011. We look forward to further collaboration with the California Energy Commission ('CEC') and its sister state and federal agencies on how best to shape policies that deliver safe, reliable and cost-effective levels of clean energy to our customers. Consistent with PG&E's environmental priorities, PG&E supports the Governor's goal of increasing clean energy supplies, and believes that existing programs should be leveraged to meet the Governor's goals with the least impact to customer cost. In that spirit, PG&E offers the following comments on questions raised at the workshop.

A. Planning for interconnecting and integrating 12,000 MWs of Distributed Generation into the Distribution System by 2020

Planning for the Future

Q1: What is your vision for your distribution system? What strategies will you be implementing to achieve this vision in the near-term (1-2 years), mid-term (2-5 years), and long-term (5 years or longer)?

A1: PG&E places a great emphasis on the safety, reliability and operational flexibility of the electric distribution system. Achieving this objective requires a combination of measures to upgrade and modernize PG&E's distribution assets. These include: modernizing the distribution system through advanced automation, monitoring and control technology; focusing capital investments to improve reliability performance, and reducing operation and maintenance expenses; standardizing design and equipment specifications to streamline facility installations and replacements; and using performance and condition-based assessments to improve reliability, increase maintenance effectiveness, prioritize repair and replacement and extend asset life.

Q2: Have you developed a plan and roadmap of distribution system upgrades to address aging infrastructure issues? How are these plans integrated with your smart grid deployment plans?

A2: PG&E has developed plans related to distribution upgrades to address aging infrastructure. Examples include replacement programs for substation transformers, breakers, cables, and wood poles. PG&E includes details for these and other plans in its General Rate Case applications (2011 recently completed, and 2014 is under development). PG&E is also building on these plans in its Smart Grid deployment plan recently submitted to the CPUC. Specifically, automation and improved control schemes being installed as part of equipment replacement projects are providing increased information to PG&E's engineers and operators and providing a foundation for further automated control schemes envisioned in PG&E's Smart Grid plans.

Q3: Have you received American Recovery and Reinvestment Act (ARRA) funds for Smart Grid projects? What is the status of your ARRA projects and how might they advance distributed generation?

A3: Yes. PG&E is a sub-recipient of a grant to the Western Electricity Coordinating Council for the Western Interconnection Synchrophasor Project. PG&E will receive $22M from the grant and will contribute $25M from ratepayer funds toward its portion of the $108M project. PG&E also received a grant to investigate the feasibility and begin environmental reviews and design work for a 300MW, 10 hour compressed air energy storage project in its service area to accommodate renewable resource intermittency. PG&E received a $25M grant and will contribute $25M of ratepayer funds. If the project proves feasible and cost-effective, a competitive solicitation to construct the project will be issued by PG&E.

Q4: What strategies will you be implementing to achieve this vision in the near-term (1-2 years), mid-term (2-5 years), and long-term (5 years or longer).

A4: Please see responses to other questions in this section.

Q5: What are the most pressing technical challenges associated with the integration of 12,000 MWs of Distributed Generation (DG) by 2020?

A5: Technical challenges to integrating large amounts of distributed generation on the distribution system vary depending on the type of DG, the amount of DG and the nature of the distribution system where the DG resource is located. In general the challenges include maintaining service voltages within limits, voltage transients, integrating with system operations, accommodating reverse power flows, forecasting resources, monitoring and control and the potential for inadvertent islanding. These challenges may affect the system's safety and reliability.

Q6: In addition to meters, please provide an overview of what commercially available technologies you are currently using or planning to secure in the next two years that will improve your ability to monitor and manage increasing penetrations of DG?

A6: As part of its Smart Grid plan, PG&E is proposing to test the efficacy of commercially available voltage control systems, also known as Volt/VAR optimization tools, in a laboratory and pilot environment. These tests will help us better understand and potentially mitigate concerns about voltage control in areas with high penetrations of solar PV. While the optimization tools are not specifically being deployed for the purpose of monitoring and managing increasing penetration of DG, they will provide additional automation and communication systems that should provide value in this area. Also, smart meters will assist the Company in monitoring and planning the distribution system, including elements associated with DG located on the customer side of the meter.

Q7: How are you planning to leverage load management programs and storage to help manage increased penetrations of DG?

A7: Load management programs and energy storage may be useful in managing increased penetrations of DG. PG&E is currently working with the CAISO on a pilot to test the efficacy of using demand response in CAISO markets to firm renewable resources. The pilot is focused on large-scale wind resource firming but may be applicable to other resource types. PG&E is also installing a 2MW battery system in conjunction with a solar PV installation at its Vaca-Dixon substation to test the use of energy storage in combination with solar PV to mitigate distribution system impacts.

B. Interconnecting DG to the Distribution System

Q1: Modifications to the Wholesale Distribution Access Tariff for some utilities and the California Independent System Operator Generation Interconnection Procedure allow for the study of interconnection applications in clusters. It is assumed that these new coordinated processes will be more efficient. Beyond revisions to these processes, please provide suggestions for how the overall process could be improved?

A1: More extensive education to developers regarding the DG interconnection process may be helpful in avoiding much confusion. In addition, increased transparency to the constantly changing DG market in reference to power purchase agreements and interconnection rules and timelines would be helpful.

Q2: What analytical tools or models do you currently use to analyze the impact of DG projects on system performance? What new tools have you added or plan to add in the next two years that will improve your ability to quickly, but safely process the growing number of interconnection applications?

A2: At the beginning of 2011, PG&E began shifting from an in-house electric distribution load-flow program to a commercially available program called CYME. PG&E will use CYME for electric planning and operating purposes including analyzing the impact that new loads and DG projects have on the electric distribution system. PG&E uses the GE PSLF program to model DG projects on the CAISO controlled transmission system to analyze impacts and determine delivery upgrades for Resource Adequacy purposes and system modifications for safe and reliable interconnection. PG&E anticipates it will take one-to-two years to implement, train personnel and become familiar with CYME. PG&E is focused on integrating CYME into its electric engineering and operating functions in 2011 and 2012. The Company does not currently have any plans to add new tools in the next two years.

Q3: Given that a growing number of wholesale or system-side renewable DG projects are applying for interconnection, many of which may not be located within or close to load centers, what planning process should be used to determine the need and timing for expanding the distribution infrastructure to accommodate these new generators? Should the process be coordinated with the CAISO? How should the costs for these upgrades be allocated and what suggestions do you have for allocating these costs in the future?

A3: Generally speaking, interconnecting new customers and/or load growth from existing customers drive the need and timing for expanding and increasing the capacity of the electric distribution system. Distribution system expansions or additional capacity requirements to interconnect new customers is based on the circumstances associated with the customer (customer location, load, service voltage and service point, etc.). New customer load applications are examined individually. Distribution system expansions or additional capacity requirements to interconnect new distributed generators are based on the circumstances associated with the specific generator. As with new customer applications, distributed generator interconnections are also examined individually (through interconnection studies).

As a general rule, it should be unnecessary to coordinate the electric distribution planning process with the CAISO. However, due to the large amount of proposed distribution and transmission generation in certain areas (such as Fresno and Bakersfield), it is sometimes necessary to coordinate with the CAISO due to the potential impact to the CAISO controlled grid.

Furthermore, CAISO is the entity charged with performing a Deliverability Assessment to determine eligible resources to be granted "Full Capacity" status for CPUC's Resource Adequacy program. This process needs close coordination with the CAISO.

Cost allocation is a somewhat more complicated question. As a general matter, PG&E believes that developers should be responsible for costs needed to interconnect and accommodate their projects on the grid, unless and to the extent that such investments produce benefits to ratepayers.

Q4: In comments filed for the May 9th Localized Renewable DG IEPR workshop, the Clean Coalition suggested that "The establishment of predefined standardized interconnection costs would avoid these issues [cost-related issues causing multiple studies of projects that add to bottlenecks in the queue and study process], providing transparency and predictability to the process while greatly reducing study requests for projects that will not be built." Would using a similar approach to Germany's in trying to predetermine costs by posing formulas that estimate the technical performance levels of a proposed DG project improve the interconnection process? Is a standardized table of assigned interconnection costs feasible? If not, why?

A4: PG&E is not familiar with the approach Germany is taking to predetermine costs. Furthermore, as outlined in the KEMA paper, elements of Germany's distribution system are very different from California's and these differences may complicate any standardized assessment of interconnection costs here.

Q4a: What are the drivers of interconnection costs? Do costs increase as volume increases?

A4a: PG&E's goal is to interconnect generation and do so in a fashion that will not jeopardize the safety, reliability, and operation of the electric system. As the volume of DG increases, the power flow, reliability, and operational concerns increase, generally resulting in higher interconnection costs. From a power flow perspective, PG&E's distribution system was designed to be fed in one direction from the transmission system to serve load. As the volume of DG increases in a particular area, the cumulative output may trigger needed upstream modifications such as upsizing distribution circuits, substations, and transmission circuits. Furthermore, from a reliability standpoint, the need for more complex protection schemes increases with more DG to address the added risk of faults and equipment failures. These protection schemes are also critical to ensure the safety of PG&E linemen working on the line. Finally, more information will be required in order for the system operators to perform their work and take into account all sources of electricity and its real-time status. In order for PG&E to retrieve this real-time status, additional telecommunication equipment will be required.

Q4b: Currently, the CAISO is using a cluster approach for interconnecting to transmission systems. After conducting a study of the impacts of a cluster of proposed projects, the CAISO determines the costs of interconnecting the cluster of projects, then allocates the cost to the number of participants in the cluster. Would this approach be feasible for the utilities to use to establish a standardized interconnection cost table for distributed generation?

A4b: The CAISO approach and model has been incorporated into PG&E's Wholesale Distribution Tariff. In addition, the unit costs used for CAISO studies have also been adopted and implemented for distribution level interconnection studies.

Q5: Should a new integrated infrastructure planning process that includes both distribution and transmission studies be established to ensure that investments in both the transmission and distribution systems are coordinated statewide?

A5: PG&E already integrates/coordinates both distribution and transmission studies when necessary. It is unnecessary to coordinate distribution studies on a statewide basis. Even in PG&E's own service territory it is generally unnecessary to coordinate distribution planning studies from a technical perspective (i.e., distribution studies in Fresno do not affect studies in Stockton). This approach would seem to add unnecessary costs and time delays, without any obvious benefits.

C. Smart Grid to Support State Environmental Goals

Q1: For the Investor-Owned Utilities: Smart Grid Implementation Plans will be filed at the CPUC on July 1, 2011. What smart grid technologies have already been included in your current General Rate Case (GRC) at the CPUC, or if you are just filing your GRC, what smart grid technologies are you requesting funding for?

A1: Due to the timing of the CPUC's Smart Grid OIR and preparation of PG&E's 2011 General Rate Case, PG&E's forecast in the 2011GRC essentially maintained spending on historical activities that are now viewed as Smart-Grid related (i.e., automation, relay upgrades, etc.). In addition, PG&E included approximately $66 million in its 2011-2013 capital expenditure forecast for key technology infrastructure upgrades necessary to lay the foundation for all Smart Grid deployment scenarios. However, the final decision in PG&E's 2011 General Rate Case resulted in a lower revenue requirement level than requested so PG&E's actual spending over the period will be less, given the reduced GRC levels. The technology infrastructure upgrades are focused in the areas of information exchange, data management and data storage.

Q2: For the Publicly Owned Utilities: What smart grid technologies have already been included in your current budget, and or do you plan to include what smart grid technologies are you requesting funding in your next budget cycle?

A2: Not applicable.

Q3: Developing and achieving the vision articulated in SB 17 for a smart grid is an evolutionary process. Smart meters are being installed throughout the state and the focus is on capturing the value of customer data and information. Moving forward, when do you anticipate focusing on distribution grid modernization?

A3: PG&E is in the process of modernizing its grid (FLISR systems, on-line DGA monitors, upgrading relays, expanding/upgrading communication systems, etc.).

Q4: What emerging smart grid technologies and software offer near term opportunities to support the monitoring and management of DG on the distribution system?

A4: Automated voltage control systems, also known as Volt-VAR optimization technology, are being tested and piloted across the industry. PG&E proposed to investigate this promising technology as part of its Smart Grid plan. Capabilities within Smart Meters are being examined to see how they could support monitoring the impacts of solar PV on the distribution system, most notable is the voltage sensing features. The inverter manufactures are examining ways for new generations of inverters to communicate generator output and other operating parameters to Smart Meters as a means of providing information about the generator to system operators.

Q5: When doing a cost benefit analysis of smart grid technologies, how do you value societal benefits associated with state goals (e.g. environmental benefits, increased renewable generation)?

A5: To the extent environmental and societal benefits such as the reduction of CO2 emissions can be directly attributable to a proposed Smart Grid project, PG&E has quantified those benefits in terms of CO2 reductions and the potential financial value of those reductions in a future CO2 market. However, PG&E has not included these potential financial benefits in its financial benefits calculations because the CO2 market has not yet been established in California. PG&E does list environmental and societal benefits as non-quantified benefits in its plan.