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June 22, 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 Renewable Integration Costs, Requirements, and Technologies

I. INTRODUCTION

Pacific Gas and Electric Company ("PG&E") appreciates the opportunity to provide comments on the California Energy Commission's ("CEC") 2012 Integrated Energy Policy Report ("IEPR") Update on renewable integration costs, requirements, and technologies. PG&E provides the following brief overview, as well as responses to questions posed to each panel during the course of the June 11, 2012 workshop on this topic.

Prior to addressing the CEC's specific questions, PG&E wishes to comment on a broader topic. During the June 11 workshop, Chair Weisenmiller spoke of the need to "cross-compare," that is, compare resources which use different technologies and compare projects that possess different characteristics. PG&E strongly supports this approach to resource planning and procurement. In contrast, California's energy policies and procurement mandates are frequently technology-specific.

An instructive example is the issue of renewable integration and the June 11 workshop itself. The workshop highlighted various ways in which the increasing amount of intermittent renewable generation will impact the electric grid. The workshop also explored three resource technologies in depth to address these impacts: gas-fired generation, demand response, and storage. However, the workshop held a separate panel on each of these resource technologies. There was very little comparison across the three technologies to assess their relative effectiveness (using engineering metrics and economic metrics) at addressing the impacts of intermittent renewable generation.

The CEC should lead the way in promoting the development of state-of-the-art analytic tools and methodologies to perform such assessments. Effective cross-comparison is a necessary foundation for better policymaking and resource planning. The CEC should also be an innovator in fostering procurement policies that focus on assembling a portfolio of projects that, *collectively*, address the necessary attributes of the electric grid. Currently, California has a procurement regime that focuses on the cost-effectiveness of individual projects considered myopically, in isolation from one another, embedded in a procurement regime rife with technology mandates and set-asides. Instead, the focus should be on the portfolio as a whole and the portfolio's engineering and economic characteristics. Shifting the focus in this direction will enable Californians to obtain electricity that is clean, highly reliable, and reasonably affordable.

Market-based mechanisms may be one way to enable cross-comparisons in a procurement context. During the course of the workshop, several participants recommended a multi-year forward market for flexible capacity to meet future renewable integration needs. PG&E endorses the development of multi-year forward capacity requirements to support flexible capacity needed to integrate intermittent renewable resources. The California Public Utilities Commission ("CPUC") and the California Independent System Operator ("CAISO") are already taking steps in this direction:

- The June 21 Decision in the 2013 Resource Adequacy ("RA") proceeding keeps the proceeding open for the explicit purpose of establishing flexibility requirements on a year-ahead basis.
- The CAISO currently has the ability to provide payments in a current calendar year to a generator needed for reliability in the next calendar year to prevent such a generator from retiring in the current year.
- Included in scope for Track 3 of the current Long-term Procurement Plan ("LTPP") is extending the existing year-ahead RA paradigm into a multi-year forward demonstration.
- The CAISO's stakeholder process initiative on Flexible Capacity Procurement is considering tariff changes intended to support multi-year forward procurement of flexible capacity.

II. INTEGRATION NEEDS CHANGE AS DISTRIBUTED GENERATION LEVELS GROW

Question 1: What integration challenges are currently being experienced at the transmission and/or distribution level at this time? How are these challenges expected to change over time?

Response: At the current level of distributed generation ("DG") penetration, the distribution system experiences the majority of integration challenges. These primarily occur on distribution feeders where multiple resources have interconnected or are proposing to interconnect to the system, requiring the addition of reinforcements. These reinforcements range from protection scheme and voltage regulator adjustments to reconductoring or even installing dedicated feeders.

As the level of DG resources grows over time, such reinforcements will be required on an increasing number of feeders. The types of changes that will be required under this scenario will vary depending on how the DG is connected to the distribution system. As DG levels increase beyond the current state however, the very nature of the distribution system will change. Present configurations will prove unsustainable. Specifically at high DG penetration, the power flow on the distribution system will become bi-directional, if not multi-directional. Currently, the grid and associated conventional generators are used together as a balancing device and PG&E's capacity margin is used to carry existing DG. These activities cannot continue under high penetration. Additionally, the current practice of using DG to serve local load directly will not be feasible at higher DG penetration levels because load diversity will not be captured and DG generation will not match the local load, requiring far more generation capacity to achieve a balance. As a result, the overall cost to serve load customers will likely increase. This does not appear to be the most cost-effective way to serve load customers.

These impacts on the distribution system will eventually necessitate changes to the transmission system as well, particularly to its daily operation. The CAISO has already initiated several changes while preparing to operate the system with 33% renewables. One such change is the addition of a renewables desk in the CAISO operations center, used to forecast fluctuations in the output of wind and solar resources. A key component of forecasting renewables is accounting for DG which is not part of the CAISO-controlled grid.

Question 2: How do the uncertainty and variability of loads and intermittent resources interact to determine the precise mix of necessary ancillary services?

Response: Loads and generation from intermittent resources vary minute by minute and are difficult to predict. Operationally flexible capacity in the form of new ancillary services may be needed to balance load and generation. Today's ancillary services are instead primarily designed to cover system contingencies (i.e., generation and transmission outages). Traditionally, conventional resources added to meet load growth have provided enough flexibility to the system. These conventional resources are being displaced by non-dispatchable preferred resources and intermittent renewables added to meet the state's 33% Renewable Portfolio Standard ("RPS") goal. In addition, the State Water Resources Control Board's ("SWRCB") Once-through Cooling ("OTC") regulation may result in the retirement of existing flexible gas-fired capacity. This has created new demand for resources that can provide flexibility and ancillary services, including: higher levels of regulation, net load following, and frequency response capacity.

Question 3: What specific ancillary services are needed to integrate different central station renewables, how much, in what location, and in what time frame?

a) Will the composition of the state's renewable resource portfolio affect the need for various ancillary services?

Response: Aside from the increased need for ancillary services explained in response to Section 2, Question 2, transmission can increase the system's flexibility to the extent that neighboring balancing authorities are allowed to share diversity in loads and generation. However, this potential solution presents opportunity costs. Transmission currently used for trading economy energy would need to be set aside to share flexibility reserves, reducing access to economy energy savings.

b) Will these needs change over time?

Response: Yes. Please see PG&E's response to question two of this section.

Question 4: What are the specific characteristics necessary to address these integration challenges in terms of response time, ramp rates, reliability, location, etc.?

Response: Preferred operating characteristics, or attributes, vary depending on the system requirements and the market products already present in the portfolio. There are two basic categories of capacity: 1) base and dispatchable capacity to meet anticipated need such as forecasted day-ahead need, and 2) flexible capacity to meet deviations from the anticipated need created by outages, forecast uncertainty and intra-hour variability of load and intermittent resource generation (e.g., spinning reserves, non-spinning reserves, regulation, and flexi-ramp resources). Please see the attachment for a more detailed explanation.

Question 5: How are renewable integration challenges at the distribution level different or similar than those posed by large-scale, transmission-delivered renewable energy? How are solutions different?

Response: The integration of renewables on the distribution grid is different than on the transmission grid because these resources alter the function of the distribution system from its original design. As more renewable resources are placed on a distribution feeder, the associated circuit needs to act more like a collector system for resources than a distribution system for serving load. To maintain power quality for customers in the future, the distribution feeder will need to be changed to accommodate electricity flowing up the feeder when DG levels exceed load on that feeder or cause reverse flow through existing radial protection and control devices. Existing power quality may be degraded if the DG output variations exceed the existing load variation magnitude and frequency.

While renewable resources can change the flow of power on the transmission system as well, its network design allows for better management of these changes. It is rather the intermittent nature of the majority of renewable generation that presents the most significant challenge to the transmission system.

III. NATURAL GAS FACILITIES PROVIDE A NUMBER OF IMPORTANT ATTRIBUTES FOR INTEGRATING RENEWABLES

Question 1: Which specific operating characteristics does/should natural gas-fired generation have in order to provide the ancillary services needed to integrate variable energy resources in terms of response time, ramp rate, reliability, incremental costs?

Response: Please see the "attributes" column of the attachment.

Question 2: What efforts are underway to increase the amount of ancillary services provided, e.g. changing market structures, dispatch protocols, etc.?

Response: Efforts are currently underway at the CPUC and CAISO to assess the amount of ancillary services needed and ensure the needed amounts are provided. The CPUC's June 21 Decision in the RA proceeding expands the proceeding's scope to include an evaluation of a flexible capacity framework for RA. PG&E supports this change.

Track 2 of the CPUC's 2012 LTPP is intended to determine the need for incremental capacity and the attributes of that capacity in order to meet operating flexibility requirements above local capacity needs. Local capacity needs resulting from the retirement of OTC fossil units in southern California will be determined in Track 1 of the 2012 LTPP. As part of the renewable integration work planned for Track 2 of the LTPP, CAISO anticipates determining the extent to which it can rely upon flexibility from neighboring balancing authorities. CAISO's work to date has focused on improving the representation of the operating requirements and excess flexibility in neighboring balancing authorities.

PG&E encourages close coordination between the CPUC's RA and LTPP proceedings, given the degree to which they overlap. In particular, the CPUC should use any information developed in 2012 during the LTPP proceeding to inform the development of a flexible capacity RA framework for the RA proceeding.

The CAISO has also undertaken multiple initiatives and stakeholder processes to improve the operations of its existing markets and develop new products to provide needed operating flexibility requirements. Amongst others, these initiatives include:

- Flexible capacity procurement for renewable integration and the risk of retirement of existing flexible capacity;
- Design of flexible capacity ramping products to manage planned increases in intermittent generation;

- Cost allocation guiding principles to provide incentives for increased operating flexibility; and
- Inter-hour scheduling pilot project with Bonneville Power Administration to more efficiently integrate renewable resources imported from other balancing authorities.

PG&E would also like to reemphasize the need to develop multi-year forward procurement requirements to fulfill the system's anticipated needs for reliability and operational flexibility.

Question 3: The recent CAISO Market Monitoring Issues and Performance report[1] concluded that existing gas-fired generation cannot recover its costs from the existing energy and ancillary services markets. What are the implications of this finding? What are the solutions?

Response: The gap between the levelized fixed cost of a new gas-fired generating unit and the generating unit's net revenue from the CAISO market is to be expected. Information from other balancing authorities reveals that this is not an issue unique to California. Net revenue analyses included in market monitoring reports for NYISO and PJM indicate that net revenue from spot markets did not equal or exceed the annualized fixed cost of a new gas-fired generating unit. However, to infer from this finding that existing revenue streams are insufficient for existing gas-fired generation is a flawed inference. Omitted from this finding are revenues from RA payments and longer-term bilateral contracts, each of which helps to close the gap. Additionally, the graph included in the CAISO report applies specifically to a hypothetical new generating unit which has capital costs included in going-forward fixed costs; going-forward fixed costs are much lower for existing gas-fired generation. PG&E therefore does not agree that there is a problem in need of "solutions." Long-term contracts are the means to obtain construction of new power plants. RA payments and multi-year bilateral contracts are the means to sustain needed existing gas-fired generation.

Question 4: Gas-fired resources not only provide the incremental ancillary services needed to integrate variable energy resources, but also system and local capacity. What other services/functions does natural-gas fired generation provide (such as inertia, voltage control)? Which of these services could not be provided by demand response ("DR") or storage? What engineering improvements have been made to increase the flexibility of gas-fired generation resources during the past decade?

Response: In the past, natural gas, conventional hydro, and pumped storage resources have provided much of the operating flexibility needed to maintain grid stability. They will likely continue to provide this flexibility into the future. These resources are able to offer:

- Frequency-response capacity;

[1] 2011 Report on Market Issues & Performance, Department of Market Monitoring, California ISO, April 2012, page 14

- Inertia needed during the sudden loss of major transmission and generation resources;
- Black start capability for system restoration;
- Regulation reserves to account for real-time variability of load and intermittent generation;
- Contingency reserve (spinning and non-spinning reserves); and
- Fast ramping capacity.

Question 5: From an engineering and/or cost perspective, what are the tradeoffs involved in providing operating characteristics that represent "flexibility" rather than simply providing energy?

Response: Resources that provide flexible capacity have the advantage of participating in multiple markets (i.e., energy, ancillary, or future flexible capacity markets), which an energy-only resource does not. However, to contribute operational flexibility, a resource may be subjected to additional costs and operation constraints not required if the resource is simply providing energy. For a natural gas plant, being "on line", a requirement of resources providing flexible capacity, equates to operating at pmin. To do so, fuel must be consumed and emissions are released. Moreover, having the capability to respond to Automatic Generation Control ("AGC") or economic dispatch signals requires the installation of additional equipment. Owners of flexible resources must consider these tradeoffs when choosing whether to sell energy or provide upward/downward flexibility. To provide energy, flexible capacity needs to be committed and dispatched to sell energy at a given output. To provide operational flexibility, capacity needs to:

- Be on line;
- Be able to respond to AGC or economic dispatch signals;
- Have unloaded capacity, not already be producing energy or be able to reduce output or increased charging; and
- Be able to sustain the delivery of energy (above pmin) for a limited period of time if asked to do so by the CAISO.

IV. AUTOMATED AND FLEXIBLE DEMAND RESPONSE CAN HELP INTEGRATE RENEWABLES IF NEEDED CHANGES ARE MADE

Question 1: Demand response has traditionally provided a variety of services through a variety of programs. What will be needed in a DR program to provide fast-response ancillary services to support renewables?

Response: To provide fast and reliable ancillary services, DR retail programs and contracts will need increased automation and flexibility. The most significant needed changes are:

- Complete automation of customer actions during DR events;
- Expectation of frequent, but short duration (less than 15 minutes) DR events;
- Expectation of DR events during the early morning and late evening;
- Expectation that DR must be available year-round;
- Shorter notification time before DR events; and
- Creation of Demand Consumption programs in addition to Demand Reduction programs.

Question 2: What are the biggest obstacles to implementing DR as a service to support renewable integration?

Response: As mentioned during the course of the June 11 workshop, customers are not generating facilities; they merely provide a service. Customers will need to receive a great deal of education and enabling technologies will need to be made available before they can be used to integrate intermittent renewable resources.

Obstacles to using DR for renewable integration abound. The current DR programs and contracts were designed to provide sustained resources during times of peak demand, not for constant events in the early morning and late evening when generation from intermittent resources experiences its highest degree of fluctuation. Additionally, demand for increasingly location-specific DR resources, removes the risk-management benefit of aggregating DR participants.

The existing framework for funding DR resources in California is entirely dependent on the three-year DR Program and Budget Application at the CPUC. This constrains the flexibility of the Investor Owned Utilities ("IOUs") and the innovation of third party DR providers in developing DR resources for renewable integration.

Current CAISO practices also limit DR's ability to integrate renewables. CAISO market rules for visibility and control of large single generators make implementing a DR resource with many, small, distributed participants cost-prohibitive. The existing CAISO market products do not accommodate for the full flexibility of DR resources. The Proxy Demand Resource (PDR) model only allows for demand reduction, therefore excluding demand consumption.

Question 3: Assuming Automated DR (Open ADR) will be necessary for Demand Response to assist in the integration of renewables in California, what are the technical challenges to ADR?

Response: If automated DR ("ADR") is to operate effectively, an open standard that removes the risk of stranded assets will be needed. The CPUC and the IOUs support the OpenADR 2.0 standard. The standard is sufficiently flexible and robust to allow DR participants the automation required to provide fast and reliable responses to load reductions or increases.

The key challenge to using ADR for renewable integration support is the determination of the correct customers, use cases, and technologies that can provide the required capabilities.

Historically, the IOUs have concentrated on helping DR participants provide peak reduction resources. The IOUs would need to reassess their approach to DR and develop expertise in the ADR program before identifying potential renewable integration opportunities. Fortunately, PG&E already has experience with deploying ADR technology for renewable integration through pilots conducted from 2009-2011 and will gain further insight during its 2012-2014 program. Through these pilots, PG&E has successfully deployed ADR technologies at customer sites and responded to simulated CAISO requests for fast responding resources at a wide variety of times.

Question 4: What are the telemetry or performance reporting needs for DR for it to be used by the CAISO or utilities to integrate renewables?

Response: Existing telemetry and performance reporting issues are significant barriers to the integration of DR resources into the CAISO market. Much like any other resource relied upon by the CAISO to maintain the stability of the transmission grid, 4-second on-going operational visibility into the aggregated DR resource for telemetry is required. Currently, the costs for implementing and maintaining the telemetry infrastructure are unreasonable for aggregated DR resources (i.e., direct air conditioning load control). If DR resources are to provide fast-response, the CAISO and Western Electricity Coordinating Council ("WECC") would need to approve other telemetry methodologies that do not rely on directly reading the equipment of each DR participant.

If DR is used to integrate renewable resources, the CAISO would also need to consider the types of operational data needed to maintain transmission grid stability (i.e., current ramp rate of a DR resource). Unlike generators, the operating capabilities of DR resources can vary significantly hour-to-hour. Moving forward, any additional incremental operating data needed by the CAISO should be clearly defined.

Question 5: As part of the Summer of 2012 efforts by the CEC, CPUC, and CAISO, it was determined that while there was hundreds of megawatts ("MWs") of demand response potential in the required locations, only a small portion of DR programs could respond within 15 minutes. How do we increase the amount of fast-response demand response to thousands of MWs within 10 years?

Response: PG&E would like to reemphasize the need for a portfolio approach to procurement, which allows utilities to focus on the attributes needed to reliably operate the system at an affordable cost to customers. That being said, the growth of cost-effective fast-response DR resources would require several developments:

- A stable multi-year funding mechanism that encourages both DR providers and customers to invest in substantial technological and operational upgrades/changes;

- A cost-effectiveness framework that differentiates DR based on their operating attributes, such as providing fast responding DR resources; and
- A reduction in the costs for implementing fast responding DR resources, including the costs for ADR technologies and integration into the CAISO markets, while maintaining the CAISO's ability to manage the system reliably.

V. WHEN COST-EFFECTIVE AGAINST OTHER INTEGRATION TOOLS, ENERGY STORAGE THAT MEETS SYSTEM NEEDS CAN HELP INTEGRATE RENEWABLES

Question 1: Are there specific transmission or distribution level renewable integration issues that current energy storage technologies can effectively mitigate? What are their respective competitive advantages over other options?

Response: High penetration of intermittent renewables could pose several challenges to California, including more frequent ramping and periods of overgeneration. This impact could be partially alleviated by resources, such as energy storage, that provide flexible capacity for regulation to help maintain system reliability, load following, managing intra-day variability, and contingency reserves. The Energy Storage Order Instituting Rulemaking ("OIR") currently before the CPUC identifies a list of 20 potential operational uses for energy storage. It is important to note that energy storage is just one of many resources that can provide operating flexibility to the electric system.

Question 2: What is the current status of storage technologies (quantity, response rate, ramp rate, duration, and costs) that could serve transmission and/or distribution level renewable integration needs? What characteristics are necessary for storage to play a meaningful role in renewable integration? How do we deploy thousands of MWs of energy storage within the next 5 and 10 years respectively?

Response: PG&E is not currently aware of the status of every type of energy storage technology. Some of the technologies with which PG&E is familiar are as follows:

- Pumped hydro: New adjustable speed pumps provide flexibility during pumping operations. This is an emerging technology with commercial installations in Japan and Europe.
- Compressed-air: PG&E's Compressed-air Energy Storage ("CAES") project (300 MWs with up to 10 hours of storage) is attempting to be the first utility-scale CAES plant to utilize a porous rock formation or depleted natural gas reservoir to store air during off-peak hours and then withdraw that air during peak hours to provide energy and/or operationally-flexible ancillary services.

PG&E would like to refer the CEC to an Electric Power Research Institute ("EPRI") report, which provides an overview of electric energy storage technologies, maturity, and cost.[2]

The characteristics needed for energy storage to play a meaningful role in renewable integration are not known at this time. PG&E's 2008 long-term Request for Offers ("RFO")[3] provides some indication as to desirable characteristics for operationally-flexible resources. Some of these characteristics include:

- Be capable of more than 300 starts per year;
- Be able to withstand short times between shutdown and restart;
- Provide fast ramp rates; and
- Offer AGC capabilities.

The CAISO Renewable Integration Studies presented in the 2010 LTPP proceeding have provided an estimate of flexible capacity needed to accommodate the 33% RPS.[4] Additional work is planned as part of the new 2012 LTPP proceeding now under way.

Regarding the deployment of "thousands of MWs of energy storage," this is yet another example of technology carve-outs, mandates, and procurement targets. Energy storage, like any other technology, should be deployed to the extent that it meets system needs and makes sense in a portfolio-based cross-comparison with other technologies. There are already programs in place that effectively incentivize storage development. The Self-generation Incentive program ("SGIP") program provides $2,000 per kilowatt ("kW") to customers who install new, qualifying standalone storage projects and storage projects coupled with other eligible technologies to meet all or a portion of their electric needs. These are popular programs; for example, PG&E's SGIP is currently fully subscribed.

In the CPUC Energy Storage OIR, PG&E outlines several challenges to the wide-scale deployment of this resource[5]:

- The current RA counting rules for energy storage are unclear;
- There is a lack of commercial operating experience;
- Pumped hydro and CAES experience long lead times; and
- Lack of integration costs which serves to mask the value energy storage technologies can provide.

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[2] http://www.electricitystorage.org/images/uploads/static_content/technology/resources/ESA_TR_5_11_EPRIStorageReport_Rastler.pdf
[3] http://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/allsourcerfo/
[4] Rulemaking 10-05-006. "Track 1 Direct Testimony of Mark Rothleder on Behalf of the California Independent System Operator" Page 43-49. http://www.cpuc.ca.gov/NR/rdonlyres/1DE789A2-29EB-4E95-9284-9E680C0113E6/0/CAISOTestimony70111_FINAL.pdf
[5] http://docs.cpuc.ca.gov/efile/CM/142506.pdf

The CEC should play a role in removing the operating experience barrier by using the Electric Program Investment Charge ("EPIC") to fund additional demonstration projects in partnership with the IOUs.

Question 3: Are there recent examples of energy storage systems that have successfully addressed the small-scale or large-scale photovoltaic ("PV") integration and/or wind resource integration issues?

Response: Renewable integration is an emerging issue. Energy storage systems deployed to address renewable integration issues have not yet sustained operating histories sufficient to determine success. PG&E is carefully tracking industry activities such as deployment of energy storage to address wind integration issues in Hawaii.

Question 4: Given the current regulatory structure, what business models exist for deploying energy storage to facilitate renewable integration? Do you have any suggestions?

Response: There are a variety of existing business models available to deploy energy storage, many of which mirror those for merchant generators, utility-owned generation ("UOG"), transmission assets, distribution assets, or end-user owned assets.

For business models specifically related to renewable integration, it is important to note that there is a cost associated with the variability and uncertainty of intermittent resources. Under the current CAISO market rules, the costs of additional ancillary services due to intermittent generation are charged to load-serving entities ("LSEs") based on their overall share of demand, rather than the generator who incurs the cost. This policy results in a lack of transparency around the true costs of integration, inhibiting quantification of the value that flexible resources provide. Allocating the costs of integration to generators based on their share of intermittency would help realize the value of flexible capacity. The PIER-funded 2020 Energy Storage Vision paper[6] echoes this request for greater transparency and cost allocation based on cost causation. By allocating the costs to generators, generators can choose to either self-supply with on-site storage, self-supply by contracting with another resource, or allow the CAISO to procure on their behalf.

Ragarding Commissioner Peterman's concern about potential inefficiencies of many resource providing integration services, there is potential for multiple intermittent resources to contract with a single flexible resource to provide ancillary services with increased economies of scale.

Question 5: How can storage complement demand response and natural gas to help integrate intermittent renewable resources at the transmission and/or distribution level? Are there portfolios of these three technologies that can provide the best value and/or lowest costs?

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[6] http://www.energy.ca.gov/2011publications/CEC-500-2011-047/CEC-500-2011-047.pdf

Response: Energy storage, DR, natural gas, and hydro can all provide flexible capacity to the system. In pursuit of a balanced portfolio, all resources should be enabled to compete on a level-playing field. An appropriate mix of projects that use these technologies depends upon the unique characteristics of the load and other resources already on the electric grid or are being planned. There is no universal answer independent of the deployment context. PG&E is working with the CAISO, other California IOUs, and other stakeholders to determine what makes engineering and economic sense for the electric grid in the CAISO footprint and in PG&E's service territory. PG&E urges the CEC to promote the development of state-of-the-art analytic tools and methodologies to perform such analysis, and to support pilot and demonstration projects that can provide data to inform such analysis.

VI. CONCLUSION

PG&E appreciates the opportunity to provide input on renewable integration issues. We look forward to participating in the remaining stages of the 2012 IEPR Update process. Should you have any questions about PG&E's comments, please do not hesitate to contact me.

Sincerely,

/s/

Claire E. Halbrook

cc: H. Raitt by email (heather.raitt@energy.ca.gov)

Attachment:

Category	Requirements	Attributes of Capacity Requirements	Use	Exists?
Products to meet anticipated need (e.g., day-ahead forecast)	Non-Flexible (Today's RA)	Generic capacity offering no operating flexibility. Only commitment is to be scheduled or available to CAISO.	Minimum load	Yes
	Shapeable (CAISO's maximum continuous ramping)	Capacity that can vary its output within the day to match the forecasted net load. The obligation of "shapeable" capacity is to deliver scheduled energy in operating hour unless forced out. Deviations from schedule are covered by Flexi-ramp and regulation. (Examples: scheduled resources and imports.)	Balance forecasted variations in net load within the day	Yes (Energy markets or self-scheduled)
	Residual Unit Commitment (RUC)	Resources procured thru RUC are available to CAISO for real-time dispatch and received a RUC marginal capacity price (except for RA resources who do not receive additional compensation.)	Additional capacity committed if not enough awarded in IFM	Yes
Products to manage variability and forecast uncertainty	Headroom/Inertia	Unloaded capacity able to respond to frequency changes instantly	Manage frequency following outages	No
	Spinning reserves	• Online, able to receive dispatch instruction within 1 minute • Able to respond and ramp within 10 minutes • Able to sustain output for 30 minutes	Resource/transmission contingencies (i.e., outages)	Yes
	Non-Spinning reserves	• Capable to receive dispatch instruction within 1 minute • Able to start and ramp within 10 minutes • Able to sustain output for 30 minutes	Resource/transmission contingencies or outages	Yes
	Regulation	Able to respond to CAISO AGC signal, and increase/decrease output continually for 15 minutes (REM) or 60 minutes (non-REM)	Intra-5 minute variability and forecast uncertainty	Yes
	Flexi-ramp (Load following or following net load)	Able to respond to CAISO's real-time Automatic Dispatch System, and increase/decrease to desired output in 5 minutes, and sustain output for 60 minutes (if awarded in IFM) or 15 minutes (if awarded in the Real-Time Pre-Dispatch process)	Intra-hourly variability and forecast	In progress
	Other products	Tbd (e.g., slower flexi-ramp, to manage multiple hour uncertainty)	Tbd	No