Pacific Gas and Electric Company™

Valerie J. Winn
Manager

State Agency Relations

77 Beale Street, B10C
San Francisco, CA 94105

(415) 973-3839
(415) 973-7226 Fax
vjw3@pge.com

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California Energy Commission
Dockets Office, MS-4
Re: Docket No. 12-IEP-1C
1516 Ninth Street
Sacramento, CA 95814-5512

Re: 2012 Integrated Energy Policy Report/Renewables: Comments of Pacific Gas and Electric Company on Electricity Infrastructure Issues in California

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 electricity infrastructure issues in California. PG&E provides the following responses to questions posed to each panel during the course of the June 22, 2012 workshop on this topic. To allow for easier review of PG&E's comments, questions of significant length were broken into subparts with the corresponding response listed below.

At the June 22 workshop, policymakers noted the complexity of the energy issues facing the state, while also indicating that there is no "one-size-fits-all" solution to addressing these challenges. Close coordination and collaboration among agencies is paramount if the state is to achieve its goal of reducing GHG emissions, while also ensuring that the electric grid can be operated in a safe and reliable manner and that customers' energy bills are affordable.

II. OPERATIONAL ISSUES MUST BE CONSIDERED WHEN CRAFTING STATE POLICIES

As noted at the June 22 workshop, simply adding more of one resource type that is not operationally equivalent to an existing resource is not the solution to the reliability concerns in Southern California. The responses below attempt to illustrate a variety of issues that need to be considered as alternatives are evaluated.

Question 1: *The State Water Resources Control Board's once-through cooling ("OTC") regulations will require many of the existing gas-fired power plants in the Los Angeles Basin to be retired, replaced, or modernized. The California Independent System Operator and the Los Angeles Department of Water and Power analyses suggest that a portion of existing capacity* *should be repowered, or its electrical equivalent developed in the Western Los Angeles sub-area, to satisfy local capacity area requirements. Are there other options that should be examined in future analyses?*

Response: Local capacity requirements play a key role in ensuring system reliability. To the extent that OTC retirements lead to a shortfall in local capacity, entities in Southern California must find ways to ensure adequate local supply is available to meet those requirements. All means of serving local capacity needs including repowering, new capacity additions, and transmission solutions should be accessible to these parties.

Question 1a: *The 2011 IEPR concluded that California needed contingency plans to deal with either extended outages of the existing nuclear power plants, or an inability to extend their operating licenses. What are the implications of this concern for the current California Independent System Operator ("CAISO") assessments?*

Response: The CAISO assessments raise a number of issues, although an extended outage at Diablo Canyon Power Plant ("DCPP") would not drive the same local capacity challenges that Southern California is currently facing with the outage of San Onofre Nuclear Generating Station ("SONGS"). With its size and location, however, DCPP is an important asset in terms of energy generation and reliable capacity and is critical to maintaining overall system reliability, even though it is not located in a local capacity requirement ("LCR") area and does not primarily serve local load. The location of replacement generation for a significant facility like DCPP would need to be carefully selected to avoid number of issues, including congestion, and limited transmission areas, among others.

First, the shutdown of DCPP would also have a detrimental impact on California's ability to meet its greenhouse gas emissions ("GHG") goals. DCPP alone produces about 18,000 gigawatt-hours ("GWh") of carbon-free electric energy annually, roughly 20 percent of PG&E's annual energy deliveries. Furthermore, DCPP generation is available 24 hours a day, 7 days a week and it avoids 6 to 7 million metric tons per year of carbon dioxide ("CO_2") emissions, compared to other available baseload generating resources.

Second, because of DCPP's unique characteristics and the location of other critical resources for integrating renewables, any limitations on DCPP's operations can have broader negative implications for system reliability. For example, DCPP energy is used in the off-peak hours to pump water at the Helms Pumped Storage Facility ("Helms"). Helms is a critical resource for integrating intermittent renewables. Without the off-peak DCPP energy, an alternative, reliable source of energy would be needed for Helms' pumping activities.

Third, as noted at the June 22 workshop, simply replacing DCPP's 24 x 7 generation with intermittent resources will not ensure system reliability or provide the needed spinning capability to address inertia in power flows. As noted above, any replacement generation or transmission projects will need comparable operating characteristics to DCPP (or more flexible operating characteristics) to ensure system reliability. In most instances, neither providing replacement energy nor adding transmission lines will be able to ensure system reliability. A holistic analysis that analyzes a combination of generation and/or transmission project solutions that would provide the comparable and multiple benefits of DCPP (reliability, economic, renewables integration, enhanced RA credit, black start capabilities) is needed.

Lastly, even if sufficient energy and capacity were available in the market to replace DCPP's generation, there would likely be a considerable increase in market prices and, therefore, a corresponding increase in consumer costs. For example, based on an analysis PG&E prepared in early 2010, the increased cost to consumers over 20 years of replacing DCPP alone could range between $3.5 billion to $16.3 billion, compared to various replacement alternatives.[1]

Question 2: *The San Onofre Nuclear Generating Station is in fact experiencing an extended outage at this time, so energy agencies and the California ISO have developed a summer of 2012 action plan which the California ISO presented at the workshop. Is there anything else that could or should be done for this summer? Are there any suggestions concerning the California ISO presentations on their plans for a nuclear generation backup study this year?*

Response: Regarding the SONGS outage, the return to service of the Huntington Beach units will improve the local reserve margin. PG&E has no additional suggestions for CAISO activities for the SONGS situation for summer 2012.

Question 2a: *Are there any suggestions for improvements in the RMI study?*

Response: PG&E looks forward to reviewing the report to be published by the Rocky Mountain Institute ("RMI"). RMI's full report should provide key details of RMI's analysis, particularly the treatment of costs to install and connect solar PV as well as any upgrades made to the distribution circuits. RMI's slides raised a number of issues for which PG&E would appreciate further explanation. PG&E's detailed questions and concerns are included in the appendix.

Question 2b: *In the time that has elapsed since the Energy Commission's 2011 IEPR workshop on nuclear power, are there updates on the implications of the Japanese tragedy, or additional seismic studies, or any other developments that the Energy Commission should consider in the 2012 IEPR Update?*

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[1] https://www.pge.com/regulation/LongTermProcure2010-OIR/Testimony/PGE/2011/LongTermProcure2010-OIR_Test_PGE_20110811_215624.pdf

Response: Given the limited time left in this IEPR Update process, PG&E suggests that the CEC hold additional discussions on the RMI study in the 2013 IEPR. Furthermore, as noted in its May 21, 2012 comments on prioritizing areas for renewable development, PG&E respectfully suggests that the CEC investigate the incremental carbon reductions that would be achieved from going beyond current mandates and the associated cost per tonne of that reduction. With this information, the CEC could investigate alternatives ways to achieve the GHG emissions reductions beyond the currently mandated programs, and assess the associated carbon cost for each alternative. This type of analysis would be invaluable to policymakers in developing flexible tools to reduce GHG emissions in the most cost-effective way for customers and the State.

Question 3: *In light of recent and forthcoming air quality management plans from the South Coast Air Quality Management District and state implementation plans from the California Air Resources Board, along with the possibility that substantial electrification will be required to achieve ambient air quality standards, it will be necessary for state agencies, the California ISO, and local utilities to adapt existing resource and transmission planning and procurement processes to provide the electricity supplies needed to meet end- user requirements. How should agencies adapt their plans to reflect these considerations?*

Response: During the June 22 workshop, PG&E was encouraged to hear comments acknowledging the complexity the state faces in advancing its clean energy policies. There is no “one-size-fits-all” solution to addressing these challenges. Close coordination and collaboration among agencies is paramount if the state is to achieve its goal of reducing GHG emissions, while also ensuring that the electric grid can be operated in a safe and reliable manner and that customers’ energy bills are affordable.

The state and its agencies need to first be very clear about their primary goal. California is best served by adopting an overarching goal of reducing GHG emissions, and providing flexible policy choices that allow the selection and implementation of the most cost-effective alternatives to achieve those reductions. There are numerous tools that can be used to achieve ambient air quality standards, including offsets, new transmission investments, energy efficiency, demand response, efficient combined heat and power, state-of-the-art natural gas facilities, energy storage, nuclear energy, and cap and trade programs, among other things. Providing flexibility to choose amongst these tools will allow policymakers and stakeholders the opportunity to assess and implement combination(s) that address the unique circumstances that may exist in particular areas in the most cost-effective way, while also preserving the environment. This approach would be far superior to new mandates or set-asides for particular technologies. Mandates may not lead to the most cost-effective solutions for customers, nor will additional renewables mandates address reliability issues like inertia and voltage support.

Planning to achieve the clean energy future must be adapted to include a wide range of scenarios, with realistic assumptions about the range of demand growth and whether preferred resources like efficient combined heat and power will materialize to meet that growth. Furthermore, planning should consider the needs of the electric system and how climate change will affect the current system. For example, in previous IEPR workshops, it was noted that an extended high temperature period can affect the transmission capabilities, as well as reduce generation output from some facilities.

Planning "just-in-time" improvements to the electric grid -- whether trying to pinpoint exactly when new transmission lines or new power plants are needed, or failing to consider the long lead time for development of large infrastructure projects like pumped storage -- will likely place California in an untenable position of guessing incorrectly much of the time about its energy infrastructure needs and could adversely affect the state's economic growth. Planning must consider how we can begin to advance these long lead time projects in the face of uncertainty, while not unduly burdening customers with the costs of investments that are not needed. This planning process could include authorizing monies for feasibility analyses and environmental studies so that more is known up front about the preferred development areas. For example, the work of the Desert Renewable Energy Conservation Plan ("DRECP") is helping identify where the preferred areas for development are in the Mojave and Colorado deserts. Similar analysis could be done in other areas to help speed the development of additional infrastructure investments when they are needed. Authorizing monies now to begin exploring the feasibility of adding new pumped storage to the system may also be desirable. Designation of transmission corridors could also help reduce the long lead time for adding new transmission lines. Pre-permitting of power plant sites could also reduce the uncertainties of timing associated with adding new generation to the electric grid. These sorts of adaptions to the planning process can help the state respond more quickly when unanticipated events occur.

These activities can also help us plan for electrification of the transportation sector. This is an emerging area and little is known about consumer behavior or how quickly we will see electric vehicles added to the system. While we can anticipate this trend, the timing, charging patterns, and interaction with existing infrastructure is less certain. Adapting our planning process to be more flexible and allowing a range of tools to meet customer demand is essential if we are to transition to an ever-cleaner energy supply and not saddle customers with ever-higher costs for decades to come.

Question 3a: *How should plans be adapted to provide electricity supplies needed to satisfy North American Electric Reliability Corporation and Western Electricity Coordinating Council reliability standards?*

Response: New efficient and clean- burning natural gas power plants might be part of the solution to air quality issues, rather than part of the problem. For example, such plants might support a switch to electric vehicles or provide back-up needed to accommodate increases in intermittent electricity supply. However, it is not yet clear how state agencies could adapt their processes to recognize and act upon such potential benefits.

Question 4: *Assuming that transportation and industrial process electrification are the key mechanisms to reduce criteria pollutant and greenhouse gas emissions, what are the planning challenges in forecasting incremental electrical energy needs, changes in hourly load shapes, and compatible sources of supply beyond those already "in the pipeline" through existing policies? How could these challenges be mitigated or overcome?*

Response: Distribution-system planning will become more complex due to residential quick-charge units for electric vehicles, some of which require as much power as a typical house. Careful management of the installation and operation of such units could mitigate that planning issue.

Electrification is a new type of load, meaning entities have little to no experience forecasting this load, its magnitude, its typical profile, nor its variability for operating purposes (for day-ahead, hour-ahead, or intra-hour scheduling and dispatch purposes). How this load will vary relative to weather, economic conditions, and other drivers also remains uncertain. Electrification load uncertainty and variability needs to be considered in determining resource and transmission/distribution needs.

Scenarios should be developed to estimate electrification load impacts and should define the uncertainty in terms of key dimensions such as magnitude and variability (both seasonally and for scheduling and dispatch purposes, as noted before). Location of charging stations, for example, is very important for its impact on transmission and distribution needs.

Question 5: *What are the implications of the ongoing transformations of the power and transportation infrastructure in the Los Angeles Basin? What are the likely complementary and/or conflicting aspects of these policies? How do we best achieve the complementary aspects? What are the challenges we need to address?*

Response: The transmission planning horizon should look beyond the 10 year horizon that the CAISO's Transmission Planning Process ("TPP") currently contemplates because major transmission projects tend to take longer than 10 years to develop. Given this long lead-time for building major transmission lines in California, the CAISO may wish to consider extending the planning horizon to 15 years.

As mentioned in the response to question 3, it is reassuring to see the various state and local agencies acting in coordination. However, this collaboration could go expanded to include other activities. For example, there is some concern that the Assembly Bill ("AB") 1318 requirements duplicate efforts already undertaken by the CAISO's OTC LCR study and the renewable integration component of the CPUC's Long Term Procurement Plan ("LTPP") proceeding. Increased coordination is also needed between neighboring balancing authorities. While it was noted during the June 22 workshop that the CAISO has been working to increase its visibility into neighboring balancing authorities, it is unclear how the LADWP and CAISO planning processes can be adjusted to examine these issues in a holistic manner.

Effective cross-comparison is a necessary foundation for better policymaking and resource planning. California's procurement system currently focuses on the cost-effectiveness of individual projects in isolation from one another as part of a procurement regime rife with technology mandates and set-asides. The focus should instead 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. No alternative, including nuclear, should be off the table to achieve this goal.

III. 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/

Valerie J. Winn

cc: M. Jaske by email (Mike.Jaske@energy.ca.gov)

Appendix: Questions on RMI Slides

Slide 6:

- Slide 6 does not list RMI's assumed cost to integrate intermittent electricity supplies. RMI explained at the workshop that it used the same cost (about $8/MWh) used by E3 in a LTPP proceeding at the CPUC. PG&E suggests that RMI's final report should document that assumption and examine the sensitivity of RMI's results to that assumption. RMI may wish to consider the treatment of integration in a May 2011 report, also funded by CEC, entitled, "California's Energy Future: The View to 2050". That report, by the California Council on Science and Technology, emphasized the need for "zero-emission load balancing" for scenarios with large amounts of intermittent resources.
- The report should clarify the basis for its assumptions regarding combined heat and power in 2030. Is the assumption based on a "least cost, best fit" analysis or a mandate?

Slide 7: The cost of residential solar PV includes installation costs and possibly upgrades to distribution circuits. The report should present RMI's assumptions about those costs.

Slide 11:

- The bar for 2012 includes 21 terawatt hours per year ("TWh/yr") from cogeneration in "Southern California." Generating that amount, at 80% capacity factor, would require about 3,000 MW of cogeneration plants. The CEC's database of California power plants[2] (last updated in April 2012) lists about 1,900 MW of cogeneration capacity in the South Coast Air Basin, or 1,100 MW less than implied by RMI's slide. RMI's report should provide an explanation for the difference.
- The "Replace" and "Transform" cases for 2030 show 31 TWh/yr from cogeneration, implying about 4,200 MW of cogeneration capacity. The report should assess the validity of that assumption, such as the type and location of cogeneration units RMI assumes, and indicate whether that capacity is thought to be flexible or baseloaded.
- In RMI's report, the bars for different scenarios in 2030 should show market <u>sales</u> separately from purchases, not merely net purchases, to indicate the extent to which Southern California is relying on other areas to accommodate excess off-peak generation.
- RMI's report should specify its GHG emission rate assumptions for 2030. The "Advance 2030" case lists 84 TWh of generation that is at least partly fossil-fueled, namely Cogeneration (26 TWh), Gas (30 TWh) and Market Purchases (28 TWh). For that case, Slide 13 shows GHG emissions of 25.3 million metric tons ("MMT"). GHG emissions of 25.3 MMT from generation of 84 TWh yields an average emission rate of about 0.3

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[2] http://energyalmanac.ca.gov/powerplants/index.html

metric tons per MWh. That emission rate corresponds to a heat rate of about 5.7 MMBtu/MWh. GE's new FlexEfficiency50 combined-cycle plant, now under development, aims at a heat rate of 5.7 MMBtu/MWh, but it's not clear that it should apply generally in 2030.

- Comparing Slide 11 and Slide 13, the "Localize 2030" case has more fossil generation than the "Advance 2030" case, but lower GHG emissions. Similarly, the "Transform 2030" case has more fossil generation than the "Replace 2030" case, but lower GHG emissions. The RMI report should explain this result. For example, the "Localize 2030" case has 33 TWh of gas generation, more than the 30 TWh in "Advance 2030", and it has 34 TWh of Market Purchases, more than the 28 TWh in the "Advance 2030" case, yet it has 24.0 MMT emissions on Slide 13, less than the 25.3 MMT for the "Advance 2030" case.

Slide 12: The RMI report should specify assumptions regarding distribution upgrade costs for solar PV, and explain whether they are included in Total Resource Costs. If RMI believes that solar PV can be precisely targeted so as to never necessitate distribution upgrades, RMI's report should specify how that targeting is to be accomplished.

Slide 17: The second bullet under "Analytical Caveats" mentions an "integration adder" used in high-penetration scenarios. RMI's report should present the adder and explain its derivation and reasonableness.