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Pacific Gas and Electric Company_Risk of Economic Retirement

Additional submitted attachment is included below.

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California Energy Commission
Dockets Office MS-4
Re: Docket No. 17-IEPR-14
1516 Ninth Street
Sacramento, CA 95814-5512

Re: PG&E Comments on Joint Agency IEPR Workshop – Risk of Economic Retirement for California Power Plants

I. INTRODUCTION

Pacific Gas and Electric Company (PG&E) appreciates the opportunity to provide written comments to the California Energy Commission (CEC) on the risk of economic retirement for California Power Plants. As discussed at the April 24 Joint Agency Workshop, PG&E agrees with the assessment of the CEC's Chair Weisenmiller and others that a number of California's electricity generating facilities are at risk of economic retirement because of: a) the overcapacity of resources in the capacity market; and b) the collapse of energy price margins due to the large amount of renewable resources scheduled or bid into the California Independent System Operator's (CAISO's) market at low or negative prices.[1] This assessment is independent of resource type and will affect all resources (i.e., natural gas, hydroelectric, solar, wind, other renewables, and nuclear power plants) that are not under contracts but exposed to short-term prices.

As numerous panelists noted, this phenomenon is triggered by low, and even negative, energy market prices that render even some greenhouse-gas-emission-free resources like hydroelectric power uneconomic to operate in the current environment.

[1] Newer renewable facilities are compensated through long-term power purchase agreements outside of the capacity and energy markets and, therefore, are not at risk of shut-down because of insufficient market revenues. However, as these long-term contracts expire, all other things equal, they would be subject to the same revenue insufficiencies seen by generators in the market today and face the risk of economic retirement.

The retirement challenge becomes how to efficiently ensure electric system reliability, especially in local areas, by providing the right compensation to those resources that are needed while also providing the right signals for an orderly retirement of excess, uneconomic capacity. This becomes a complex assessment when looking at system, local, and flexible needs over a multi-year time frame when the electric system is rapidly changing. For example, significant changes include retirement of once-through cooling units and higher renewable standards (each with different attributes to contribute to system reliability), along with load shifting from a largely centralized IOU procurement model to a much more decentralized model where community choice aggregation and other retail providers are responsible for procurement. In addition, the units at risk of retirement need to look at a multi-year capital investment plan for those that will not be retiring.

There are three alternatives that agencies could explore to address these issues:

1. **Redesign of Resource Adequacy (RA) program** to provide longer-term commitments, specific locational values (i.e., unbundling the local-area aggregations), and better integration of any necessary reliability procurement by the CAISO into the current RA timelines and construct.
2. **Consider Moving toward a Centralized Capacity Procurement Model, where the CAISO** could procure the most efficient mix of resources to ensure the right resources are kept and provide clear signals that others, if uneconomic, can plan to retire in an orderly fashion; or,
3. **Establish a capacity procurement agency** for local or other longer-term needs that might be more efficiently procured on a centralized basis with the costs/benefits being allocated to all load serving entities (LSEs).

II. IN THE NEAR-TERM, THERE IS AN INCREASED RISK OF GENERATOR RETIREMENT FOR RESOURCES WHOSE COMPENSATION COMES FROM SHORT-TERM MARKETS.

As discussed at the workshop, many generators that are not under mid- or longer-term power purchase agreements (PPAs) in California are facing revenue-sufficiency challenges. This is due to two primary factors: 1) low CAISO energy market prices driven down by the influx of new renewable generation (which is compensated outside the markets through long-term PPAs), and 2) low capacity market prices due to a capacity surplus resulting from investment in new renewable facilities to meet state policy goals.

Given these trends, a number of California's gas-fired generators are at an increased near-term risk of economic retirement and, over the next several years, additional resources, including hydroelectric resources, may become uneconomic to continue to operate. The challenge then is to ensure the California Public Utilities Commission's (CPUC) RA program and CAISO markets (including its backstop procurement mechanisms) do three things: a) provide the right price signals in both the energy and capacity markets to ensure those resources that are needed for reliability are compensated to remain in operation; b) provide clear signals and prices for resources not needed to retire in an orderly fashion; and c) do a) and b) efficiently and avoid incurring excess costs and procurement through poor program design.

III. IMPACT ON PG&E-OWNED GENERATION

PG&E owns and operates numerous electricity generation facilities, including the 2,200 megawatts (MW) Diablo Canyon nuclear power plant, nearly 3,900 MWs of hydroelectric facilities,[2] and 1,400 MWs of clean natural-gas-fired power plants.

As PG&E noted at the workshop, the value of electric power plants have declined significantly, particularly over the last few years, because of declining prices and an abundance of renewable generation in the state. PG&E's customer demand for electricity in California also continues to decline due to the expansion of rooftop solar programs, community choice aggregation, and energy conservation programs.

PG&E regularly assesses its generation asset usage in terms of market prices and customer demand to ensure we are providing safe, reliable, and affordable energy for our customers. This evaluation applies to all of the projects within PG&E's Utility Owned Generation (UOG) portfolio, including solar and fossil-fueled facilities, to ensure our portfolio aligns with the needs of our customers. PG&E recently submitted a withdrawal of its application to renew the Federal Energy Regulatory Commission (FERC) license for the DeSabla-Centerville Project, located in Butte County. The project was about 12 years into relicensing when the decision was made.[3] PG&E also recently sold its Merced Falls Project to the Merced Irrigation District, rather than completing the relicensing process and continuing to own and operate the project. Likewise, PG&E previously decided not to relicense its Kilarc-Cow Creek Project, and is awaiting a decommissioning order from FERC.

Similarly, as noted at the CEC workshop, PG&E and several parties have submitted a proposal to the CPUC to retire the 2,200 MW Diablo Canyon nuclear power plant at the end of its current Nuclear Regulatory Commission (NRC) license life. This proposal was driven by numerous factors, including the increase of the Renewable Portfolio Standard to 50% by 2030, the doubling of energy efficiency goals under Senate Bill 350, the challenge of managing overgeneration and intermittency conditions under a resource portfolio increasingly influenced by solar and wind production, the growth rate of distributed energy resources, and the potential increases in the departure of PG&E's retail load customers to Community Choice Aggregation (CCA).

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[2] 89% of PG&E's hydroelectric capacity is from storage or pondage. The remaining 11% is from run-of-the-river Generation.

[3] PG&E's relicensing of various hydroelectric projects has taken between 10 and 29 years.

In these cases, the current and anticipated cost of production at these facilities is expected to exceed the cost of alternative sources of renewable power on the open market and, when combined with both the expected increasingly costly and complex conditions for continued operation and the significant costs associated with protracted relicensing proceedings, the projects would be uneconomic to continue to operate.

Such decisions to retire or divest assets are very fact-specific, based on the unique characteristics of a facility. PG&E includes all bundled-customer benefits as part of its decision-making process around the future of generating facilities, including value for resource adequacy and any Reliability-Must-Run (RMR) or other contracts. However, while a generating facility may provide a grid benefit to customers, if market mechanisms do not compensate the units sufficiently for satisfying that need, it may not provide the best solution.

IV. MARKET CONDITIONS MERIT REEVALUATION OF THE RA PROGRAM

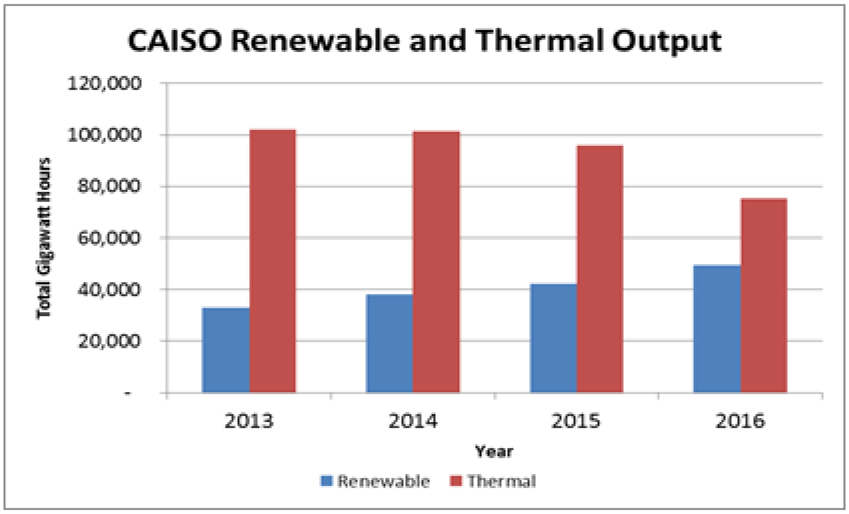
In both the energy and capacity markets, conditions merit a reevaluation of the RA program. Each market is described below.

Energy: Low energy prices and low capacity prices are also seen in today's market, as new renewable capacity has been installed to meet the state's capacity goals. As shown in Table 1, as capacity is increased by 50% in a three-year period, market energy prices have declined by nearly 50%. This means energy revenues to generation through the market declined significantly at the same time as short term capacity prices were likely also declining due to the increase in supply. Table 2 shows similar results of renewable and thermal output, with thermal output declining as new renewables come on line over the period.

Table 1

	CAISO Avg Marg Cost for Energy	Maximum Wind and Solar Generation (Capacity Proxy)
2014	$ 48.04	8,431
2015	$ 33.23	9,452
2016	$ 29.46	11,576
2017	$ 27.87	12,284

Table 2



Capacity: As a result of the new capacity and few retirements, planning reserves are high, reflecting a surplus of capacity in the market. In the 2015 Summer Assessment (the last year for which CAISO published planning reserve margins); the planning reserves margin was 39.1% ISO-wide. When compared to a planning reserve requirement of only 15%, suppressed short- term capacity prices are a natural outcome.

The CAISO's Market Monitoring Report from May 2016 also explained that, "Net operating revenues for many – if not most – older existing gas-fired generators are likely to be lower than their going-forward costs. However, a substantial portion of the state's 15,000 MW of older gas-fired capacity is located in transmission constrained load pockets and is needed to meet local reliability requirements. Much of this existing capacity is also needed to provide the operational flexibility required to integrate the large volume of intermittent renewable resources coming on-line. However, this capacity must be retrofitted or replaced over the next decade to eliminate use of once-through cooling technology. This investment is likely to require some form of longer-term capacity payment or contracting."[4]

V. ALTERNATIVES TO TODAY'S RA PROGRAM SHOULD BE EVALUATED

Action needs to be taken to redesign the RA program as it pertains to the local RA procurement area in light of load shift and the market economics. Absent swift action, inefficient local procurement by LSEs (i.e., too much in one local area and not enough in others) may result. In that case, the CAISO would have to revert to using an increasing amount of RMR contracts and the CAISO would also use its backstop procurement authority, Capacity Procurement Mechanism (CPM) more often, both signs of capacity market flaws with additional

[4] From the CAISO Department of Market Monitoring Annual Report (May 2016), pages 16-17.

costs allocated back to LSEs on top of the local procurement costs.[5] These CAISO actions also do not provide longer-term signals or incentives for planned operation in the three to five year time frame. Review of the RA program to consider longer-term timeframes and efficient local procurement is particularly important in light of the load shift toward CCA and expanding retail choice. Historically, IOUs served the majority of load and had an open position to fill to meet the needs of load so in their procurement they could balance the needs of all local areas; now, PG&E is in a similar position to the generators, and is often a seller, rather than a buyer, of capacity.

PG&E proposes some alternatives to consider:

1. Redesign of RA program to provide longer-term commitments, specific locational values (i.e., unbundling the local area aggregations), and better integration of any necessary reliability procurement by the CAISO into the current RA timelines and construct.

For example, in determining the current local RA requirements, the CAISO looks at reliability in particular local reliability areas (LCAs). In setting requirements for its jurisdictional LSEs, the CPUC aggregates these LCAs into larger areas for procurement purposes, and requires its LSEs to show procurement on these larger regions. LSEs have the incentive to purchase from low-cost LCAs, potentially leaving generators in high-cost LCAs uncontracted and resulting in a potential reliability issue for the CAISO. Splitting up these aggregations and setting requirements at the LCA level could address this issue, but would introduce other issues (e.g., how to sell few units to many buyers).

2. Consider moving toward a Centralized Capacity Procurement Model, where the CAISO could procure the most efficient mix of resources to ensure the right resources are kept and provide clear signals that others, if uneconomic, can plan to retire in an orderly fashion; or, areas that would then choose the most efficient mix of resources to ensure the right resources are kept and that others are allowed to retire.

This alternative might be best for both reliability and cost. It would allow critical units to be maintained while providing signals to others to retire. The CAISO could recover local costs through transmission rates. The CPUC would then still run its RA program and could reduce system and flexible RA requirements by the capacity procured by the CAISO to support local needs so that LSEs do not over procure.

[5] A RMR contract is between the CAISO and a generator needed to maintain grid voltage/reliability. The CPM provides the CAISO the ability to procure capacity to maintain system reliability when needed, including plants that are at risk of retirement. To qualify for RMR or CPM status, units must be uncontracted, and be needed for reliability purposes in the next calendar year.

3. Establish a capacity procurement agency for local or other longer-term needs that might be more efficiently procured on a centralized basis with costs/benefits being allocated to all LSEs.

Similar to the CAISO as central procurement agent, a state agency could perform the procurement function and allocate out the costs and benefits. The only way to really efficiently procure for all local areas is to have one agency procure the most economic mix in all areas and consider the reliability constraints. This would be done best by the CAISO since it has the best view of the various reliability constraints in each area. That said, if the CAISO was unwilling, another agency could fill the role and allocate costs and RA benefits for LSEs who would then fulfill the remaining (system and flexible) RA obligations.

VI. CONCLUSION

PG&E appreciates the opportunity to participate in the Joint Agency Workshop and to submit these comments on the risk of economic retirement of power generating facilities. Please contact me if you have any questions or wish to discuss matters further.

Sincerely,

/s/

Valerie J. Winn

Responses to Questions from the CEC:

Power Plants at Risk of Retirement

- How are "risk of retirement" issues different in competitive markets like the California ISO versus traditional integrated utilities?

In a traditional integrated utility, decisions to retire generators are made centrally by a single entity and can be well coordinated with other decisions about maintaining reliability.

- Which existing plants are likely to be retired for economic reasons and why?

Generally, the plants not under mid- or longer-term contracts that have the highest costs and lowest revenues are the most likely to consider retirement. In some cases, the CAISO may intervene through its tariffed procurement mechanisms (RMR or CPM) if the potential retirement would have an adverse impact on reliability.

- What are the key services that at-risk power plants provide?
  - Local area reliability
  - Flexibility to ramp up or down at a high rate
  - Ancillary services (regulation, spinning reserve, non-spin reserve)
  - Inertia
  - Others?

The services provided by a risk-of-retirement plant are dependent on the specific plants under consideration (i.e., those not under contract that are less economic). All of the key services listed above might be reduced by plant retirements. Other key services could include voltage support and black start capability and/or system restoration attributes. As plants retire, the CAISO, CEC, and CPUC will need to consider the supply-demand balance for each of these services. Services that have a tighter supply-demand balance, like local capacity in some areas, are likely to have a larger impact on reliability. Other key services may depend on the type of power plant; for example, in addition to black start or system restoration capability, hydroelectric facilities provide numerous non-energy benefits, such as water delivery, recreation, and environmental benefits.

- Are there plans to not pursue relicensing of some hydro facilities?
  - Are there related aging infrastructure issues with hydro facilities?

Yes, the average age of PG&E's hydro system is over 75 years old, and many facilities are over 100 years old. Investments are required to keep the system operating safely and reliably, but the costs in many cases outweigh the energy benefits provided by the Projects.

- Are there issues with aging infrastructure related to aging geothermal power plants?

  Not applicable to PG&E.

- What are plans for repowering of wind facilities?

  Not applicable to PG&E.

Local Reliability Needs

- Which California local areas/regions appear to be the most vulnerable for reliability, and why?

  - Which power plant retirements have implications for local reliability?

  All power plant retirements in local areas will have an impact on local reliability. When considering local reliability impacts, the primary focus will be on those plants that are the most effective at resolving transmission constraints (and the CAISO publishes effectiveness factors for units), how tightly constrained the local area is in terms of MWs of local units needed and MWs of generation in the area, and the size of the plants. Ultimately, the most efficient procurement of the right plants in local area should be done on a centralized basis.

  What are the reliability attributes needed from generation resources that are not being captured in existing revenue frameworks?

  - What changes would need to be made?

  Existing revenue sources include energy and ancillary services markets, system capacity, local capacity, and flexible capacity.

  Regarding local resources, CPUC and CAISO requirements include aggregate showing requirements across geographic areas and do not require all needed capacity in every area be procured. This structure provides an incentive for LSEs to procure the cheapest sources to meet showing requirements. Better aligning actual requirements with reliability needs would provide revenues to local units that are actually needed. This could be accomplished by disaggregating local procurement requirements into smaller areas for showing; however other issues will still exist, as discussed previously.

  Regarding flexible resources, the current definition of flexibility is based on a 3 hour ramp requirement, and a large number of resources can count as flexible, so there is a surplus of flexible capacity, and little or no premium for flexibility. The definition of 'flexible capacity' should be tightened, so fewer resources would qualify and include those facilities that do meet more of CAISO's reliability needs.

- What type of performance is expected or appropriate from a generation resource on a grid with renewable energy, storage, demand response, as well as conventional fossil resources?

Ideally all generators should be dispatchable and able to meet the system needs (load/resource balance) and respond to any disturbances in the system to ensure reliability to the greatest extent possible.

- What form of capacity is required for supporting a reliable electric system today?

Peak, flexible, and locational capacity will all be required. The need for capacity to meet peak demand has been reduced due to the buildout of renewable capacity to meet RPS requirements, but peak load will still need to be met in the future. Due to that same build out, flexible capacity will become even more important and locational capacity is critical to support how PG&E's transmission system was built. In addition, it is important to consider capacity from a variety of fuel sources because over-reliance on one fuel source could result in reliability impacts to the system when that fuel source is not available.

Generation Attributes and Performance

- Which services provided by power plants have formal California ISO market product and which do not?

All services provided by power plants have formal requirements whether those services are explicitly compensated or not.

  - What are the broader benefits of a more diverse fuel mix?

There are significant benefits from a diverse mix of generation that rely on different fuels, with a primary benefit being reliability at lowest cost. Over-reliance on one fuel source can create reliability impacts when that fuel is scarce. Furthermore, over-reliance on one fuel source can have cost consequences when that fuel is expensive.

- With increasing intermittent renewables, do fossil power sources such as gas, and out of state coal, provide greater grid reliability than is expected from energy storage or demand response?

To the extent that it is easier and cheaper to store and transport fossil fuels, rapid start fossil power is more reliable than short-term (e.g., four hours or less) energy storage and demand response (which can have limited calls per season or hours per call). Long-term electric energy storage that can store energy for days, weeks, or perhaps even months in advance (like PG&E's Helms Pumped Storage facility) can readily provide rapid response storage from a variety of fuels well in advance of weather or grid-related supply limitations, without compromising near-term short-term storage capabilities. The CAISO is better positioned to opine on the effective grid reliability resulting from out-of-state generation resources.

  - Is this factor affecting any resource retirement plans?

- What new metrics are needed for valuing these resources to capture the full diversity of performance that can be provided?

  PG&E has no comment at this time

- What form of capacity is required that is capable of reliably supporting a high renewables electric system today and into the future?

As discussed, a mix of capacity attributes that include the ability to ramp quickly is required.

What Are Possible Approaches and Solutions

- What are the GHG implications from continued use of natural gas plant to satisfy flexibility and other reliability requirements?
- What value should be given to GHG reduction versus reliability considerations alone?

Due to the changing electric system, all parties will need to consider how to balance reliability needs with other goals of the state, including carbon reduction and cost considerations.

- Given the focus on more flexible resources, are traditional reliability metrics, such as 1 outage in 10 years, still in step with economic benefit analysis?

Yes, a 1 outage in 10 years standard can apply equally to not having capacity to meet peak demand as well as not having the generation mix to accommodate switching output from resources.

- Should incentives for forward contracting change for periods of high demand or scarcity?
  - Market and/or price changes?
  - Changes in contract terms?

Yes, in periods of scarcity longer-term contracting will provide greater stability for continued investments in units including those for capacity improvements. This is critical in local areas where the supply is limited. However, for system resource adequacy, where there is excess supply and units do not have key locational value, forward contracting is not necessary at this time.

- What lessons can be learned from other parts of the country?
  - What kind of focused research might help answer some of these questions?

  Other parts of the country are struggling with accommodating state preferences for particular fuels and generation in their markets. For example, state policies and wholesale markets in Eastern ISOs and RTOs was the subject of the May 1-2 FERC technical conference.