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California Energy Commission

Dockets Office, MS-4
Re: Docket No. 14-CHP-1
1516 Ninth Street
Sacramento, CA 95814-5512

Re: PG&E Stakeholder Comments on California Energy Commission Combined Heat and Power (CHP) Staff Workshop

I. INTRODUCTION

Pacific Gas and Electric Company ("PG&E") appreciates this opportunity to respond to staff questions and to comment on material provided at the Combined Heat and Power ("CHP") workshop held by California Energy Commission ("CEC") staff on July 14, 2014.

PG&E supports clean, efficient CHP generation that provides cost-effective and reliable electricity to customers and advances California's statewide goal of reducing greenhouse gas ("GHG") emissions. PG&E currently promotes onsite and export-capable CHP of differing sizes through various programs, including: 1) the administration of incentives for customers to purchase distributed CHP generation under the Self Generation Incentive Program ("SGIP"), 2) the offer of a Feed-in Tariff ("FiT") Power Purchase Agreement ("PPA") for as-available CHP of less than 20 megawatts ("MW") under Assembly Bill 1613, 3) the purchase of electricity through a pro-forma PPA with CHP Qualifying Facilities ("QF") with nameplates less than 20 MW under the Public Utility Regulatory Policies Act ("PURPA"), 4) the purchase of electricity from as-available CHP facilities with nameplates greater than 20 MW under the pro-forma Optional As-Available PPA, and 5) the issuance of Requests for Offers from CHP with nameplates over 5 MW pursuant to the QF/CHP Program Settlement Agreement or bilateral negotiations.

II. SUPPORT FOR ANALYSIS OF FUTURE CHP DEVELOPMENT

With respect to further incentives for CHP development within California, PG&E supports analysis that considers the benefits and costs of new CHP in the context of future electrical system needs. When considering additions to its generation resource portfolio, PG&E places a high priority on resources that have high operational flexibility and thus support system reliability, are affordable for all customers, and have low environmental impact. As California continues towards an ever-cleaner energy supply, conventional topping-cycle fossil-fueled CHP may only provide limited GHG emissions reductions. Other forms of CHP, such as bottoming-cycle and renewable, may provide greater GHG reduction opportunities.

The CEC should examine several issues when considering the merits of a policy in support of conventional fossil-fueled CHP. Like the CEC staff, PG&E places a high priority on formulating an objective standard for measuring the effectiveness by which topping-cycle GHP reduces GHG emissions. The amount of GHG emissions from resources displaced by CHP generation is another essential element of the efficacy of CHP resources. The GHG emissions of CHP resources themselves are subject to variation based on operating conditions. The potential of the energy markets, customer behavior, technological advancement, and other factors to influence the efficiency of CHP must be recognized.

A widely accepted measure of the GHG performance of CHP technology is a methodology known as the "Double Benchmark Standard." The Double Benchmark reveals whether a CHP generation facility is more efficient than the two processes that typically would be used if they were not displaced by the CHP facility, to produce the same amount of heat and electricity.

The benchmark for displaced heat sources should reflect the efficiency of currently available boiler technology. New boilers sold for end use in California must comply with a minimum of 79 to 80 percent thermal efficiency standard regardless of their size or application.[1] Mid-efficiency boilers, which slightly exceed the minimum requirement, commonly have efficiency ratings between 83 to 88 percent. PG&E and other California investor-owned utilities ("IOUs") provide energy-efficiency rebates in this category to promote further deployment of mid-efficiency boilers.[2] Additional public information about boiler usage should be examined to

[1] California Code of Regulations Title 20, *CEC 2014 Appliance Efficiency Regulations*, Gas-fired boilers – p. 114-115 http://www.energy.ca.gov/2014publications/CEC-400-2014-009/CEC-400-2014-009-CMF.pdf

[2] PG&E Energy Efficiency Appliances Rebate Catalog, p.5, at http://www.pge.com/includes/docs/pdfs/mybusiness/energysavingsrebates/incentivesbyindustry/boilers_waterheating_catalog_final.pdf

establish the typical thermal efficiency of boilers expected to be deployed in California, particularly those that would be displaced by a new CHP system.

The California electric grid continues to contain ever-cleaner resources and thus displaced grid emissions are expected to decline over time. Improvements in combined-cycle technology will result in declining heat rates of new gas facilities.[3] In practice, increased cycling duty to integrate intermittent generation may exert some upward pressure on combined-cycle heat rates. Overall, however, a higher penetration rate of renewable generation, once-through cooling retirements, and the cap-and-trade program are expected to cause displaced grid emissions to further decline over time. CEC Staff has proposed a regression-based approach for displaced grid emissions using historical data from gas-fired resources. PG&E believes this is a good starting point but suggests that Staff adjust its model to account for renewables and other GHG policies that may result in carbon neutral generation on the margin for significant parts of the year. [4]

Finally, the overall operational performance and thermal utilization of conventional CHP should be closely monitored to determine whether GHG reductions are actually occurring according to modelling assumptions. If deployed and operated in an inefficient way, conventional fossil-fueled CHP facilities, unlike renewable generation or bottoming-cycle CHP, has the potential to increase GHG emissions. Currently, there is no public source that reports the thermal utilization of larger CHP. However, both the Air Resources Board ("ARB") and the CEC have reporting requirements that could fill this need. The ARB collects operating performance and thermal utilization of existing CHP facilities through its GHG Mandatory Reporting Requirement. The ARB should make this information public at a level of aggregation consistent with protecting business-sensitive information of the facilities – to be available to guide public policy. The CEC collects similar information under its Quarterly Fuel and Energy Report (QFER Form 1304). The CEC should restructure its survey questions to provide useful information for determining CHP operating efficiency.

Other issues that arise around PG&E's involvement with CHP are the interconnection process and Departing Load Charges ("DLCs"). PG&E has been consistently working with

[3] See: California Energy Commission, 2011, *Thermal Efficiency of Gas Fired Generation in California.*

[4] *See*, E3's 2014 Study: *Investigating a Higher Renewables Portfolio Standard in California*. According to E3, in the 33% RPS scenario, overgeneration occurs during 1.6% of all hours, amounting to 0.2% of available RPS energy. In the 50% RPS Large Solar case, overgeneration must be mitigated in over 20% of all hours, amounting to 9% of available RPS energy, and reaches 25,000 MW in the highest hour. (E3 Study, p. 107) https://www.ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf

customers, vendors, and other stakeholders to improve the interconnection process, including the implementation of online applications. As for DLCs and Non Bypassable Charges ("NBCs") that apply when power is consumed onsite, PG&E reminds stakeholders that the California Legislature established these to mitigate the cost shift to all other customers. Examples of NBCs are the Public Purpose Program charge, which included funds for energy efficiency incentives and low income rate discounts, the Department of Water Resources ("DWR) Bond Charge, which covers the costs that DWR incurred to procure short-term power during the energy crisis, and the Competition Transition Charge, which covers the above market costs of QFs, many of which are CHP projects. As customers, some CHP already enjoys exceptions from some NBCs. Further exemptions for customers who install CHP from such charges simply raise costs for other customers.

PG&E provides its answers to Staff's stakeholder questions in the following sections.

III. PG&E'S RESPONSE TO CEC STAFF QUESTIONS

I. Market Characterization and the Benefits and Costs of CHP

1. *What benefits, if any, do existing small and large onsite and exporting CHP resources provide to electric utilities and the ISO?*

CHP resources represent a sizeable portion of PG&E's energy supply portfolio. PG&E has PPAs with over 2,300 MW of CHP.[5] In 2012, PG&E procured about 8,700 GWh of energy from CHP resources, representing 10% of the total energy supplied.[6]

CHP contribution to system reliability, operational flexibility, and price for exported energy and capacity are all key determinants of identifying CHP value to utility customers. Historically, CHP resources have been paid administratively determined energy and capacity prices. These prices have often exceeded market prices and resulted in above market costs flowing into utility customers' rates.[7] Although the

[5]. PG&E July 2014 Cogeneration and Small Power Production Report and April 2014 QF/CHP Settlement Semi Annual Report http://www.pge.com/includes/docs/pdfs/b2b/qualifyingfacilities/cogeneration/2014july.pdf; http://www.cpuc.ca.gov/PUC/energy/CHP/settlement.htm

[6] PG&E 2013 CEC Form S2- http://energyalmanac.ca.gov/electricity/s-2_supply_forms_2013/

[7] PG&E recovers above market costs of associated with eligible contracts signed prior to December 20, 1995 including eligible Qualifying Facilities (QFs) restructuring costs through Competition Transition Charge (CTC). PG&E recovers the "net capacity costs" from CHP contracts entered into under the rules of the QF/CHP Settlement of 2011 through Cost Allocation Method ("CAM"). PG&E 2015 forecasted CTC revenue requirement is $ 83.2 Million and CAM revenue requirement is $219.5 Million. CHP resources

QF/CHP Settlement Agreement introduced a degree of competition between CHP resources through the competitive procurement process, majority of PPAs executed pursuant to the Settlement Agreement have resulted in above market electricity costs being passed on to IOU customers.

PG&E notes that some of the advocated benefits of CHP, such as energy security and back-up power, are available to the customer owning the CHP, but may not support the grid or be available to IOU customers. Other claimed benefits of CHP, such as transmission and distribution deferral - to the extent that they can be realized - are time and location specific. These should be studied in an integrative manner for all distributed resources. [8]

2. *What benefits/attributes do grid operators want from CHP resources? Under what circumstances can CHP provide those characteristics?*

A modern power generation portfolio should perform well across three key areas: high operational flexibility to ensure system reliability, affordability for all customers and low environmental impact. PG&E values these three attributes across all procured resources, including CHP resources.

Given the expected increase in intermittent deliveries from renewable resources, the future grid will need to be more responsive and flexible than it is today. Additions of flexible generation, including CHP facilities to the extent it is flexible, can help integrate intermittent renewables.[9] However, adding inflexible generation, such as traditional baseload CHP, will potentially exacerbate grid reliability challenges associated with integrating intermittent renewables and may contribute to overgeneration. There are some inherent challenges and tradeoffs in running topping-cycle CHP unit in response to grid needs versus running it to match thermal need and sustaining efficiency. Theoretically, a bottoming-cycle CHP configuration may be more responsive to the grid needs and still provide GHG emissions reductions.

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contribute about 40% of CTC-eligible capacity and 68% of CAM-eligible capacity. See: PG&E 2015 Energy Resource Recovery Account and Generation Non Bypassable Charges Application, available online at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M092/K073/92073926.PDF

[8] Assembly Bill 327, approved in October 2013, provides such opportunity to consider integrative distributed energy resources planning. PG&E will be submitting its Distribution Resources plan by July, 2015.

[9] PG&E has signed some hybrid CHP offers through CHP RFO process. For example, PG&E Kern River Cogeneration Company (KRCC) is a baseload -combined heat and power-dispatchable agreement. http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4190-E.pdf

Environmental impact is a key area of focus for energy policymakers in California. With respect to CHP, the attention to environmental impact is often focused on the question of GHG emission reductions. As California continues towards a cleaner future, conventional fossil-fueled CHP may only provide limited GHG emissions reductions. Other forms of CHP, such as bottoming-cycle, may provide greater GHG reduction opportunities.

3. *Access to useful operational and economic data from utilities and CHP system owners is often restricted.*

    a. *What currently unavailable types and/or sources of data would allow for more complete and accurate analysis of the benefits and costs of CHP?*

    As mentioned above, there is currently no public data source that reports the operational performance and thermal utilization of large CHP in California. This information is critical to evaluate GHG performance of fossil-fueled topping-cycle CHP. Two state agencies, the ARB and the CEC, have reporting requirements that could potentially fill this need.

    While economic information about the operation of individual CHP facilities may help reviewers to better quantify the cost of generation that meets the Double Benchmark, other legitimate interests may weigh against the public disclosure of such information. For example, information that generators consider proprietary business information is protected from public disclosure. PG&E would oppose the public disclosure of its market sensitive energy procurement costs to market participants unless such disclosure is subject to the requirements and safeguards adopted by the California Public Utilities Commission ("CPUC"). The IOUs are also bound by the CPUC decisions on confidentiality of CHP efficiency data.

    b. *How should this data be collected, obtained, and/or distributed?*

    The ARB Greenhouse Gas Mandatory Reporting Regulation ("MRR") report has a comprehensive list of questions to collect large CHP operational and thermal utilization information. PG&E's comments in the ARB's 2012 MRR amendments rulemaking suggested how MRR information could be used to evaluate the operational GHG performance of conventional CHP.[10] ARB should make public the operating performance of existing CHP facilities it collects through the MRR reports at a level of aggregation consistent with protecting business-sensitive information

The CEC collects similar information for its Quarterly Fuel and Energy Report (QFER Form 1304). However, the CEC survey questions are not structured in a way that provides useful information for determining CHP operating efficiency. PG&E has informally requested the CEC to amend the QFER CHP reporting requirements but has yet to see the changes implemented. [11]

4. *What CHP cost studies are needed to better understand and compare CHP resources to other resources?*

   There is limited information available about the cost and economic potential of cleaner forms of CHP such as bottoming-cycle and renewable CHP. These forms of CHP should be studied further.

   Additional fundamental analysis and research is needed to find ways to enhance the electric generation flexibility of existing CHP resources and to configure new CHP to be more flexible while maintaining efficient thermal utilization. The economic value and costs of achieving additional operational flexibility could be studied at the same time.

5. *What other categories of CHP benefit and cost are relevant, and how should each be defined and/or quantified in ways that are meaningful to the system and the State?*

   State future goals should focus on cost-effectiveness of the GHG emissions reduction measures across all sectors of the economy. The benefits and cost of CHP as a means of GHG emissions reduction should be studied from a total resource cost perspective and in the context of the future electrical system need.

[10] PG&E Comments on the 2012 Proposed Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, p. 3-4 http://www.arb.ca.gov/lists/ghg2012/3-091012_mrr_comments_final.pdf, pp. 3 and 4.

[11] PG&E 2012 Integrated Energy Policy Report Update/Combined Heat and Power Comments, p. 20, Attachment A http://www.energy.ca.gov/2012_energypolicy/documents/2012-02-16_workshop/comments/Pacific_Gas_and_Electric_Company_Comments_2012-03-12_TN-64134.pdf

II. Economic Barriers & Regulatory Challenges to CHP

1. *What are the most significant economic factors that contribute to the decision by a public or private developer to invest in CHP (e.g. upfront cost, ongoing operation and maintenance, electricity rates, price of natural gas, internal business decision making processes)?*

There can be factors other than economic criteria that may influence the business decision to invest in CHP. Nonresidential customers typically have a high hurdle rate for making capital investments outside their core business, even when it makes sound economic sense. Prior to the launch of PG&E's third CHP Request for Offers ("RFO") in January 2014, PG&E directly called 27 parties, including industry trade groups and participants in PG&E's previous CHP RFOs, and expressed strong interest in receiving offers that are low GHG- emitting or provide GHG emissions reductions. PG&E received the following industry feedback:

- Food Processing: The seasonality of the industry makes year-round power production difficult.
- Steel: Steel manufacturing produces corrosive low-grade waste heat that is unusable for electric generation.
- Cement: Do not consider themselves in the "power business" and typically would consume any energy produced.
- Oil & Gas: Expect in that decreases in steam need beginning in the next five years or so will make a lot more facilities available for tolling agreements.

Additionally, in our commercial experience, PG&E has observed that the steam host need for large industrial customers is typically less than 300,000 MBtu/hour. [12] Appropriately sized topping-cycle gas turbine to meet the thermal host need would be substantially smaller than the size of a conventional central station combined-cycle or simple-cycle gas turbine. This size disparity leads to a considerably higher per unit cost for most CHP systems.

[12] Where 1 MBtu = 1000 Btu

2. *What impacts do departing load charges have on the viability of developing new CHP resources?*

   Non-bypassable Charges (NBCs) or Departing Load Charges (DLCs) would only factor into the economics of a CHP resource if the power were being used to supply onsite load. NBCs relate to specific categories of utility costs that are recovered through customer rates. They have been established by the Legislature and implemented by the CPUC generally in support of a public policy. NBCs are generally associated with utility costs related to a given obligation (e.g., low-income rates, or power procurement mandates) that are allocated across large customer segments. These costs do not diminish in magnitude if a larger industrial customer reduces its grid usage through the installation of a CHP unit. Therefore, the customer should not be able to avoid paying its share of these costs simply because the customer uses distributed generation to meet all or part of its energy needs. Exemptions from NBCs do not reduce the overall cost; they simply increase the cost burden on other customers.

   Examples of NBCs include Public Purpose Program (PPP) charges (that fund energy efficiency and low-income ratepayer assistance programs), the costs that the state incurred to procure power during the energy crisis that is being recovered through a 20 year bond, and the costs of power purchases mandated through various state policy directives (e.g., the 33% Renewable Portfolio Standard) that would become stranded when certain customers switch to distributed generation or direct access to meet all or part of their load. The Legislature (and the CPUC) historically established these NBCs because of electric industry restructuring (e.g., the Competition Transition Charge ("CTC") to recover the above-market costs of Qualifying Facilities (including CHP) and as a result of the failure of electric restructuring in California (e.g., Power Charge Indifference Adjustment ("PCIA"), and DWR Bond Charge.)

   Some types of generation have already received exemptions from some NBCs when supplying a portion of the onsite load. For example, clean customer generation systems up to 5 MW (including CHP systems) that are eligible for the SGIP program are exempt from the DWR Bond Charge, the PCIA, and the CTC for the first MW of generation. They are also exempt from the New System Generation Charge ("NSGC"), which was established by the CPUC as a non-bypassable charge to implement the CHP Cost Allocation Method ("CAM") from the QF/CHP Settlement agreement. If the CHP facility is over one MW, but meets the definition of "ultra-clean and low emissions" in California Public Utilities Code Section 353.2, the departed load is responsible for the DWR Bond charge, but is exempt from the PCIA and NSGC. Distributed renewable generation that is eligible for the net metering programs is exempt from all of these charges for all onsite generation.

PG&E does not support further exemptions because this simply increases the cost burden on other customers. PG&E is aware that CHP proponents have claimed that NBCs stand in the way of their decision to invest in CHP, but is not aware of any sound analysis that demonstrates the extent to which this is the case, or that would justify the granting of NBC exemptions given the adverse impact from doing so on other customers. Specifically, the granting of additional NBC exemptions for customer load supplied by onsite CHP might improve the economic profile of the adopting customers, but at the expense of all other customers, and as such does not represent sound state policy. PG&E supports investigating the impacts of other potential barriers such as the need to acquire the engineering expertise necessary to design, build, own and operate a CHP installation where that is outside the customer's normal course of business, and the financial hurdle posed by a major capital investment.

3. *Are exit fee allocations that continue indefinitely, without transition or restriction, appropriate for CHP facilities?*

PG&E presumes that the term "exit fees" is being used synonymously with "NBCs". As such, PG&E believes the "appropriateness" of the NBCs, including duration: 1) has been determined by the Legislature already, 2) is being appropriately implemented by the CPUC.

As described above, the Legislature created NBCs, generally as a way to mitigate cost shifts to bundled customers. NBCs serve to protect customers who perhaps are not able or willing to install distributed generation, but who would otherwise pay for utility obligations incurred on behalf of customers who do have the choice.

It is incorrect to assume that exit fees continue indefinitely. As part of the implementation of the NBCs, the length of individual charges is determined by the length of the commitment. For example, any NBCs from the above-market contracts entered into by DWR during the energy crisis will expire as those contracts expire. If, in the future, above market payments to CHP were no longer made, then this component of NBCs would expire as well.

4. *What regulatory challenges and barriers lead to new CHP project delays or failure (e.g. interconnection process, financial incentives, contracting issues, cap and trade)? Please provide specific examples of how these challenges were, or were not, overcome.*

   PG&E has been working with customers, vendors and other stakeholders to improve the interconnection process. For example, the Rule 21 Settlement, approved in September 2012, established a clearer path for distribution resources, including CHP, of all sizes, and particularly those that could export to the grid, to interconnect using a standard procedure.[13]

   PG&E has enhanced the interconnection application process by moving it online, helping to ensure greater accuracy of input data and faster processing of applications. Through efforts with stakeholders, the CEC, and CPUC, PG&E examined its protection requirements to find more efficient protection solutions that meet safety requirements and in some cases, save both time and expense relative to previous protection solutions.

   More recently, the CPUC approved the Distribution Group Study process, in which PG&E played an integral drafting role. The Distribution Group Study Process fills in a gap that existed in the interconnection process, and will now benefit distribution level projects that interact with each other on the distribution system but do not have impacts with the transmission system.[14] PG&E is also playing a leading role in the efforts to establish standards for smart inverters, which will allow resources to interconnect to the grid in a way that will have fewer system impacts and to be more reactive to system conditions.

   PG&E notes that the cap-and-trade program is likely to incentivize efficient CHP. PG&E is not sure why this is identified as a regulatory barrier.[15]

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[13] D.12.09.018 September 13, 2012, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M028/K168/28168335.PDF

[14] D.14-04-003, April 10, 2014

[15] Efficient CHP that exports power to the electric grid is incentivized by cap-and-trade. Administratively determined exporting CHP energy prices provide compensation for GHG costs. CHP providing onsite power is also likely to be incentivized if cap-and-trade and AB 32 program costs embedded in retail rates reflect an appropriate carbon price signal. PG&E expects avoided carbon costs in electricity purchases will be greater than direct carbon costs for new efficient onsite CHP. See: 2012 IEPR PG&E Comment on the Staff paper, p.9 http://www.energy.ca.gov/2012_energypolicy/documents/combined-heatpower/comments/Pacific_Gas_and_Electrics_Comments_2012-10-22_TN-67954.pdf

5. *What regulatory changes, if any, are needed to better balance utility interests, CHP developer interests, thermal host needs, and State GHG reduction targets?*

   Any forward procurement of new resources should be consistent with the system and local capacity need determination in the CPUC Long Term Procurement Plan ("LTPP"). The CPUC's LTPP proceeding is the appropriate venue to identify long-term resource needs and authorize IOUs to procure new resources. The CPUC recently issued a ruling in the 2014 LTPP proceeding seeking comments on CHP issues, including CHP GHG reduction targets.[16]

   Utility customer interests need to be addressed. PG&E necessarily evaluates the value of CHP generation and related PPAs to its customers, and works to obtain cost-effective CHP power on behalf of its customers.

6. *A key feature of AB 1613 is that it allows for export and payment of excess electricity.*

   a. *Does the current AB 1613 feed-in tariff provide enough financial support to enable individual projects to be sized and developed with appropriate technology to meet the thermal load of the host facility?*

      AB 1613 required the CPUC to establish a "standard tariff" for qualifying CHP generators to sell their *excess electricity* to the IOUs. The CPUC explained that, "The AB 1613 program seeks to enhance the efficiency of an existing class of industrial boilers and reduce GHG emissions by providing incentives to install heat recovery steam generators and turbines at the tail end of these existing units"[17]

      The CPUC-approved AB 1613 feed-in tariff provides a combined price for exported energy and capacity and additional compensation for GHG emissions cost associated with exported power. The AB 1613 "all-in" payment was based on the Market Price Referent ("MPR") that the Commission adopted as a benchmark, pursuant to the Renewables Portfolio Standard ("RPS") legislation. The MPR, in turn, was calculated using the CEC's cost model for a combined-cycle combustion turbine ("CCCT"). A CCCT is expected to provide firm capacity; however, the AB 1613 PPA is for as-available capacity, only. This suggests that

[16] 2014 LTPP (R.13-12-010), Administrative Law Judge's Ruling Seeking Comment on CHP Issues. Located at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M098/K861/98861127.PDF

[17] CPUC decision D. 09-12-042.

the administratively determined AB 1613 PPA payments exceed the market value of the product.

In summary, PG&E does not have information as to what constitutes enough financial support. PG&E's concern, on behalf of its customers, is to obtain good value from its purchases of CHP power.

b. *How does the availability of the feed- in tariff affect your decision to pursue a CHP project in California?*

NA

c. *Are there any deficiencies in the current implementation of AB 1613? Please explain.*

NA

d. *What should be done to better inform project developers about the requirements of the ISO and utility interconnection processes for electricity export?*

NA

III. Meeting California's CHP Goals

1. *Is there adequate economic and technical potential for CHP resources to achieve State goals set out in the Governor's Clean Energy Jobs Plan (6,500 MW of new CHP capacity by 2030) and the Air Resources Board's Scoping Plan for AB 32 (6.7 MMTCO2E annual emissions reduction by 2020)?*

The CEC has identified technical and economic potential for CHP in California that PG&E believes is optimistic.[18] ARB relied on an earlier CEC report when setting the CHP potential in the 2008 Scoping Plan. Later CEC reports indicate smaller potential than the first report, relied on by ARB and Governor's Clean Energy Jobs Plan (see Table 1).

[18] Assessment of California Combined Heat and Power Market and Policy Options for Increased Penetration November 2005, Combined Heat and Power Market Assessment, ICF for CEC, April 2010 and Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, ICF for CEC, June 2012
http://www.energy.ca.gov/2005publications/CEC-500-2005-173/CEC-500-2005-173.PDF;
http://www.energy.ca.gov/2009publications/CEC-500-2009-094/CEC-500-2009-094-F.PDF;
http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

In 2013, PG&E retained Energy and Environmental Economics, Inc. ("E3") to study cost of achieving carbon abatement, as measured in terms of Carbon Metric $/Ton, from CHP consistent with the policy goals laid out in the 2008 Scoping Plan of the California Global Warming Solutions Act ("AB 32"). PG&E/E3 Carbon Metric report concludes that CHP is not likely to offer significant GHG savings in the 2020 timeframe. Relative to the CEC reports, E3 predicts fewer GHG savings per MW when considering sensitivities around CHP operational profiles, technology performance, and improving separate heat and power performance over time. E3's study it assumes a cleaner 2020 avoided grid emissions rate but does not adjust for RPS interaction. It should be noted that the PG&E/E3 report studied same topping-cycle, natural gas-fired CHP technologies as listed in the 2010 and 2012 ICF for CEC reports.

Table 1: CHP 2020 MW and GHG Reduction Estimate

Study Name	**2020 New CHP Estimate (MW)**	**2020 GHG Reduction Estimate (MMT CO_2e)**	
2008 ARB Scoping Plan[1]	4000	6.7	
2011 Scoping Plan CEQA Update	N/A (not reported separately from EE)		
2010 ICF for CEC[2]		Assumes no RPS interaction	
Base Case	2,240	1.93	
High Case ("all-in")	5,532	6.05	
2012 ICF for CEC[3]		No RPS Interaction	w/RPS Interaction
Base Case	1,499	1.8	0.5
High Case	4,865	5.5	2.0
2013 E3/PG&E Carbon Metric[4]		Assumes no RPS interaction	
Match MW from 2012 ICF Base Case	1,502	0.6	
Growth Similar to PURPA Boom	3,940	2.2	

Recent Historical Growth	394	0.05
Sources: 1. California Air Resources Board, 2008 Climate Change Scoping Plan, A Framework for Change 2. Combined Heat and Power Market Assessment, ICF for CEC, April 2010, CEC-500-2009-094-F 3. Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, ICF for CEC, June 2012, CEC-200-2012-002-REV 4. 2013 PG&E/E3 CHP Carbon Metric Report. This report is available on request.		

2. *How should the State meet these goals?*

   Recent CEC studies and the PG&E/E3 Carbon Metric report have found that the GHG savings from CHP are smaller than the ARB 2008 Scoping Plan estimate, even in the cases where CHP MW market penetration exceeds the ARB goal of 4,000 MW of additional CHP by 2020 (see

   Table 1). CHP's place in the broader framework of California's energy policies, and whether CHP will help achieve California's long term energy and environmental goals, is worthy of additional study.

3. *Should the State set CHP procurement targets to address specific CHP facilities, projects, or technology types (e.g. existing efficient CHP, bottoming- cycle CHP, renewably- fueled CHP, new highly efficient CHP)?*

   No. PG&E recommends against establishing IOU targets for specific technologies because procurement to meet such targets will not result in least-cost procurement that best fits the utility's portfolio needs and the state's reliability needs. Any forward procurement of new resources by IOUs should be consistent with the system and local capacity need determination in the CPUC LTPP. The CPUC's LTPP proceeding is the appropriate venue to identify long-term resource needs and authorize IOUs to procure new resources.

   PG&E notes that non-utility energy service providers, whether Community Choice Aggregators or Direct Access providers, are typically not obligated to purchase power from CHP resources as part of any mandated procurement program. This raises fairness and competitiveness concerns that should not be exacerbated by additional CHP procurement targets.

4. *Do the eligibility requirements of existing CHP programs align with market needs? If not, what changes are needed to stimulate market participation?*

   PG&E notes that CHP Feed-in-tariff ("AB 1613") eligibility criteria treat electrical energy and thermal energy output on equivalent basis and requires an overall total system efficiency of 62% on HHV basis.[19] This undifferentiated treatment is inadvisable as electrical energy is a more valued and flexible form of energy than thermal energy[20]. PG&E recommends the use of Double Benchmark standards to compare the performance of conventional fossil-fueled CHP to separate heat and power sources.

IV. Technology Innovation to Overcome CHP Barriers

1. *What are new opportunities and applications for on- site and exporting CHP resources both large and small (e.g. CHP coupled with Carbon Capture Utilization and Sequestration technologies, energy storage for excess electricity, thermal storage for excess thermal energy)? How should the state encourage these technologies (e.g. bottoming-cycle/waste heat to power, use of renewable fuels, microgrids)?*

   PG&E supports use of Electric Program Investment Charge ("EPIC") funds for new and emerging clean CHP technologies research and development, if such funding will not result in duplicate efforts. The targeted use of grants should allow for more controlled and productive studies of potential CHP applications.

2. *Which technologies, systems, components, and applications should RD&D prioritize to advance the capabilities and opportunities of both small and large CHP*

   NA

[19] *Guidelines for Certification of Combined Heat and Power Systems Pursuant to the Waste Heat and Carbon Emissions Reduction Act.* California Energy Commission. 2010. See: http://www.energy.ca.gov/2009publications/CEC-200-2009-016/CEC-200-2009-016-CMF-REV2.PDF

[20] Physically it is impossible to convert 3.413 MMBtu of heat into 1 MWh of electrical energy. However, it is possible to convert 1 MWh of electrical energy to 3.413 MMBtu of heat.

V. Electrical Generation Unit and Reference Boiler Efficiency

1. *How should CHP systems be categorized, if at all, for the purpose of comparing them to separate heat and power (e.g. size, technology type, application)?*

   CHP reduces GHG emissions if the CHP facility produces fewer emissions than separate heat and power for a given amount of electricity and heat. CHP systems can be classified in three categories to compare to separate heat and power:

   i. Fossil-fueled topping-cycle CHP

   ii. Bottoming-cycle CHP

   iii. Renewable-fueled CHP

   The Double Benchmark test for fossil-fueled topping-cycle CHP requires comparison of the GHG emissions from the CHP with the GHG emissions that would be produced by grid resources and an onsite boiler producing the electrical output and thermal output equivalent of the CHP Facility.

   In the case of bottoming-cycle CHP with no supplement firing, only waste heat is captured to provide additional electricity, thus requiring no additional fuel input to generate electricity. Thus, it can be considered a carbon neutral electricity generation resource. GHG reductions can be estimated as emissions that would have been produced had the electricity output equivalent of CHP been generated from the grid resources.

   Renewable-fueled CHP would generate both electricity and thermal energy from carbon neutral resources. GHG reductions can be estimated as emissions that would have been produced had the electricity and thermal output equivalent of CHP been generated from the grid resources and an onsite boiler.

2. *What method(s) should be used to determine the effective heat rate of displaced grid electricity? What key factor(s) should be considered (e.g. operational capabilities, time of day, line losses)?*

   Estimating the grid emissions displaced by CHP requires an estimate of the type of generation displaced by the CHP system. Reasonably accurate estimates can be made using a power system dispatch model to determine how emissions for generation in a specific region are impacted by the shift in the system demand curve and generation mix resulting from the addition of new CHP resources.

CEC Staff has proposed a regression-based approach for displaced grid emissions using historical data on gas-fired resources. PG&E believes this is good starting point but suggests that Staff adjust its model to account for renewables and other GHG policies that may put carbon neutral generation on the margin for significant parts of the year. [21] This approach should also be benchmarked by production simulation modeling, as discussed above.

3. *What method(s) should be used to determine the efficiency of displaced thermal resources? What key factor(s) should be considered (e.g. thermal load size, thermal utilization level, historical equipment purchases/performance, new technologies)?*

Thermal efficiency of boilers varies by load size, heat application type and age of the boilers. New CHP systems are likely to displace construction of new onsite boilers. Therefore, it is appropriate to compare performance of new CHP with efficiency of new displaced boilers. Performance of existing CHP system may be compared to performance of existing boilers.

Boiler sizes are typically classified by energy consumed per hour (MBtu/hour).[22] Natural gas fired boilers can be categorized as water heating boilers and steam boilers. Table 2 lists the CHP technologies studied in the 2012 CEC report.[23] CHP thermal output is converted from 'Btu/kWh' to 'MBtu/hour' to make it easy to compare with displaced boilers.[24] Table 2 also lists CHP systems comparison to typical boiler sizes (<300 MBtu/hour, 300-2,500 MBtu/hour and > 2,500 MBtu/hour).

California Code requires a minimum of 79-80 percent thermal efficiency rating on all sizes and applications of boilers.[25] Mid-efficiency boilers, which slightly surpass the legal standards, are commonly produced with ratings between 83 to 88 percent. Within the conventional market, there is some movement towards mid-efficiency

[21] See 2014 E3 *Investigating a Higher Renewables Portfolio Standard in California* Study. In the 33% RPS scenario, overgeneration occurs during 1.6% of all hours, amounting to 0.2% of available RPS energy. In the 50% RPS Large Solar case, overgeneration must be mitigated in over 20% of all hours, amounting to 9% of available RPS energy, and reaches 25,000 MW in the highest hour, page 11- 13 https://www.ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf

[22] Where, 1 MMBtu = 1000 MBtu = 1000,000 Btu

[23] Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, ICF for CEC, June 2012

[24] 80% capacity factor is assumed to covert CHP kW rating to kWh/hour of electrical generation

[25] Codes of Regulation Tittle 20, CEC 2014 Appliance Efficiency Regulation, Gas-fired boilers – page 114-115 http://www.energy.ca.gov/2014publications/CEC-400-2014-009/CEC-400-2014-009-CMF.pdf

boilers.[26] PG&E and other IOUs provide energy-efficiency rebates in this category to promote further deployment of mid-efficiency boilers.[27] High-efficiency units are rated 90 percent and higher. These are typically the condensing boilers and currently are more common at small-scale applications. [28] However, a hybrid of conventional and condensing boiler can be deployed for high thermal use application, increasing overall large boiler system efficiency.

PG&E believes that this merits further research. Additional public information is needed to establish the typical thermal efficiency of boilers expected to be deployed in California, particularly those that would be displaced by a new CHP system.

Table 2: CHP thermal output conversion from Btu/kWh to MBtu/hour

Technology Type	Size (kW)	Heat Rate* (Btu/kWh)	Thermal Output (Btu/kWh output)	Hourly Avg Electrical Output (kWh/hour)	Hourly Thermal Output (MBtu/hour)	Displaced Boiler Size
Micro-turbine	65	13,286	5,297	52	275	<300 MBTUh
	185	11,663	4,062	148	601	300-2500 MBTUh
	925	11,663	4,062	740	3,006	>2500 MBTUh
Fuel Cell	300	7,640	2,046	240	491	300-2500 MBTUh
	400	9,500	2,484	320	795	300-2500 MBTUh
	1200	7,640	2,023	960	1,942	300-2500 MBTUh
Reciprocating Engine	100	11,488	6,091	80	487	300-2500 MBTUh
	800	9,750	4,300	640	2,752	>2500 MBTUh
	3000	9,400	3,850	2,400	9,240	>2500 MBTUh

[26] Cite http://library.cee1.org/sites/default/files/library/7543/CEE_GasComm_BoilerInitiativeDesc_16May2011.pdf

[27] PG&E Rebate Catalog - http://www.pge.com/includes/docs/pdfs/mybusiness/energysavingsrebates/incentivesbyindustry/boilers_waterheating_catalog_final.pdf

[28] https://www.energystar.gov/index.cfm?c=most_efficient.me_boilers

	5000	8,325	2,950	4,000	11,800	>2500 MBTUh
Gas Turbine	3000	13,414	5,664	2,400	13,594	>2500 MBTUh
	10000	10,800	4,062	8,000	32,496	>2500 MBTUh
	40000	8,990	3,109	32,000	99,488	>2500 MBTUh

* Note Heat Rates are expressed in Higher Heating Value (HHV)
Source: Derived from 2012 CEC CHP report (Table 39 - 42)[29]

4. *How can the State measure and quantify thermal utilization for the purposes of determining the GHG emission reduction benefits of CHP? Should all CHP facilities be required to meter useful thermal output and report that information to state agencies?*

   Thermal utilization is critical to determining overall CHP GHG performance. The current structure of the Self Generation Incentive Program already includes a rigorous performance-based incentive feature with payments keyed to the successful continuation of electricity production, thermal utilization and maintaining overall GHG performance.[30] All natural-gas CHP systems 30 kW and larger are required to install a metering system.[31]

   As discussed above, currently, there is no public data source that reports the operational performance of large CHP in California. However, two state agencies, the ARB and the CEC, have reporting requirements that could potentially fill this need. ARB has a comprehensive list of questions under the ARB MRR requirements and ARB should make public the operating performance of existing CHP facilities at a level of aggregation consistent with protecting business-sensitive information – so as to be available to guide public policy (see Section I: Q3.b. , p. 6 response for more information).

[29] California Energy Commission, 2012, Combined Heat and Power: 2011-2030 Market Assessment Report, p. 91-99

[30] CPUC Decision 11-09-015, pursuant to Senate Bill 412 (2009)

[31] CPUC 2013, Self-Generation Incentives Program Handbook, page 56 http://www.cpuc.ca.gov/NR/rdonlyres/0DDABA86-9DF1-41C7-AD08-FF5B255155FA/0/2013_SGIP_Handbook_v1.pdf

VI. Energy Commission Staff Proposed Methodology for Estimating Fuel Displacement

1. *Is the Energy Commission staff's approach to estimating fuel displacement reasonable? If not, please explain why.*

Staff has proposed a regression-based approach for displaced grid emissions using historical data on gas-fired resources. PG&E believes this is good starting point as it provides a simple and publicly verifiable framework.

Staff should adjust its approach to account for the presence of renewables and other GHG policies. Energy and Environmental Economic Inc., 2014 Investigating a Higher Renewables Portfolio Standard in California study predicts over-generation potential with 33%, 40% and 50% RPS scenarios. Overgeneration occurs when 'must-run' generation (such as non-dispatchable renewables, CHP, nuclear generation, run-of-river hydro) and thermal generation which is needed for grid reliability is greater than load plus exports.[32] Table 3 lists overgeneration statistics for 33% RPS, 40% RPS, and 50% RPS Large Solar scenario. Staff's approach should account for overgeneration hours where renewable resources (or carbon neutral resources), would be on the margin. PG&E also recommends that this approach be benchmarked against production simulation model-based analysis.

Table 3: Overgeneration Statistics for 33% RPS, 40% RPS and 50% RPS Large Solar Scenario

Overgeneration Statistics	33% RPS	40% RPS	50% RPS Large Solar
Total Overgeneration			
GWh/yr.	190	2,000	12,000
% of available RPS energy	0.2%	1.8%	8.9%
Overgeneration frequency			
Hours/yr.	140	750	2,000
Percent of hours	1.6%	8.6%	23%
Extreme Overgeneration Events			
99th Percentile (MW)	610	5,600	15,000
Maximum Observed (MW)	6,300	14,000	25,000

Source: E3 Investigation Higher RPS in California study – pg. 107

2. *Is the Energy Commission staff's approach to the treatment of renewable energy appropriate? If not, please explain.*

[32] E3 Investigating Higher RPS in California – page 10

PG&E believes the staff's approach is a worthwhile starting point. However, PG&E believes that the staff approach should account for the overgeneration hours where renewables (instead of thermal resources) can be on the margin.

3. *How could the method be applied across programs so that it creates beneficial comparison without interfering with existing program-specific displacement metrics?*

   It is not clear from the paper how Staff proposes to use its methodology (for example, in which venues and for what purposes). More information would be helpful in determining how it could be applied across programs.

4. *Is the use of annual heat rate values (versus seasonal values) sufficient given the purpose and scope of the method? If not, please explain and propose an alternative.*

   Yes, the use of annual heat rate values is appropriate for studying resources that are expected to generate a similar quantity throughout the year (for example baseload CHP). However, customers programs that are expected to impact seasonal demand (example Demand Response-Smart AC program, food processing CHP) would require a more granular look, including seasonal heat rate values.

5. *Is the use of a single, state-wide heat rate projection appropriate? If not, please explain and propose an alternative.*

   Yes, the use of state-wide heat rate projection is appropriate for displaced grid emissions accounting.

6. *Is the use of two heat rates categories (peaking and load following) adequate? If not, please explain and propose an alternative.*

   The use of two heat rate categories is a good starting point. As noted, overgeneration conditions resulting in non-fossil generation on the margin should constitute a third category.

7. *Does the approach sufficiently address the issue of imported electricity? If not, please suggest ways that it could be improved.*

   Accounting for imported electricity is a complex topic. Currently, imports represent a considerable portion of California electricity consumption with unspecified imports representing about 16% of the total system power.[33] California has quite flat load growth

[33] California instate generation - 71%, Unspecified imports 16.4% Refer: CEC Total System Power for 2012 http://energyalmanac.ca.gov/electricity/total_system_power.html

projections with increased energy efficiency and onsite distribution generation growth.[34] More instate renewables are developed to comply with 33% Renewable Portfolio Standards. In addition, Environmental Protection Agency Clean Air Act Section 111(d) for existing power plants will further affect the resource availability for unspecified imports in the Western Energy Coordinating Council ("WECC") and will promote cleaner gas-fired generation. Considering these factors, the Staff's current approach of looking primarily at instate gas-fired generation is a reasonable proxy for displaced grid resources, with the qualification that the impact from overgeneration conditions should also be considered.

8. *Do you agree with the line loss factor used? If not, please explain and propose an alternative*

The line loss factor of 7.8% assumed by the Staff seems to be greater than historically observed line loss factors in California. A CEC 2011 study suggests that California average system losses for transmission and distribution ranged from 5.4 percent to 6.9 percent during 2002 to 2008.[35] To our knowledge, there is no updated estimate of line losses. We recommend Staff to provide a public study or data source for the assumed 7.8% line loss factor. In addition, how line losses are expected to change over time should also be studied.

9. *Do you agree with the heat rate floor used? If not, please explain and propose an alternative.*

No. As discussed, overgeneration needs to be examined and accounted for.

[34] CEC 2013 IEPR - California annual electricity load growth rates range from 0.64% - 1.37%
http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-SD-V1.pdf

[35] See: California Energy Commission, 2011, *A Review of Transmission Losses in Planning Studies*
http://www.energy.ca.gov/2011publications/CEC-200-2011-009/CEC-200-2011-009.pdf

IV. CONCLUSION

PG&E appreciates the opportunity to comment on these issues and looks forward to the CEC's next steps. Please contact me if you have any questions or wish to discuss any of these matters further.

Sincerely,

/s/

Madeline R. Silva

cc: Jason Harville by email (jason.harville@energy.ca.gov)