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California Energy Commission
Dockets Office, MS-4
1516 Ninth Street
Sacramento, CA 95814

RE: Docket No. 14-CHP-1

Dear Commissioners:

Attached are Southern California Gas Company's responses to the questions from the CEC workshop concerning the benefits, challenges, and practical solutions to incentivizing combined heat and power resources in California. Should you have any questions, please do not hesitate to call.

We appreciate the opportunity to provide input in this important proceeding.

Yours sincerely,

Tamara Rasberry

Southern California Gas Company Responses to Combined Heat & Power in California Questions for Stakeholders

CEC Docket 14-CHP-1

The following responses from the Southern California Gas Company (SoCalGas) were prepared in response to the request for written comments following the July 14, 2014, California Energy Commission (CEC) Combined Heat and Power (CHP) Staff Workshop. SoCalGas appreciates the CEC's effort to explore in detail issues and opportunities pertaining to the installation of CHP in California and hopes that the information provided below will be helpful to the CEC.

I. Market Characterization and the Benefits and Costs of Combined Heat and Power

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

The following operational benefits have been recognized by the CPUC: [1]

- **Decreased congestion and increased system reliability**
- **Greater resource adequacy, improved stability and power quality including VAR support,**
- **Transmission and Distribution (T&D) and capacity investment deferrals and reduced electricity supply costs resulting from decreased demand**
- **Increased economic productivity and investment for host sites resulting in higher employment and economic growth.**

CHP is the most efficient way to generate energy from fossil fuel. It is widely recognized for reducing GHG emissions compared to separate electrical and thermal production by way of efficiency gains and avoided T&D losses. CHP can provide black start capability, can support micro-grids, and offers locational bonuses in electrically constrained areas.

Accelerated adoption of CHP can also help displace a portion of lost generating capacity[2] **in the wake of the San Onofre Nuclear Generating Station (SONGS) closure and the replacement of once through cooling (OTC) facilities. The state plans to fill the gap of SONGS lost generating capacity by increased adoption of Preferred Resources (includes CHP) with incremental natural gas generating capacity. Accelerated adoption of efficient, on-site CHP capacity could offset a portion of central natural gas generating capacity needed due to the closure of SONGS and would be funded by private businesses instead of ratepayers.**

CHP can achieve these characteristics with close coordination between proposed CHP facilities and gas and electric providers.

[1] Operational Benefits recognized in D-09-08-026, Decision for Adopting Cost-Benefit Methodology for Distributed Generation, CPUC, August 20, 2009.

[2] "Preliminary Reliability Plan for LA Basin and San Diego," Prepared by Staff of the California Public Utilities Commission, California Energy Commission, and California Independent System Operator, DRAFT August 30, 2013.

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

   No response

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?

      Data regarding electricity price versus electricity demand would make the costs and benefits of CHP more apparent. This data could be used to determine if reductions in load due to increased CHP generation would cause a reduction in electricity costs.

      Furthermore, identifying resource-constrained areas/locations on the grid that would most benefit from CHP would be beneficial.

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

      Electric IOU's and Municipal utilities, with CAL ISO's guidance, could work collaboratively with CHP providers to gather pertinent information without exposing customer information and make this information available to the public.

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

   Cost studies regarding price impacts of reduced load due to CHP, factoring in a variety of locational bonuses, would assist in understanding and comparing CHP resources to other resources. Studies that show the impact CHP could have on businesses that utilize the technology in terms of costs savings, operational benefits, and job creation would also be helpful.

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?

   T&D infrastructure deferment due to increased CHP deployment: quantify the infrastructure benefits of deploying CHP in both capacity constrained areas and areas with infrastructure nearing end of useful life.

II. Economic Barriers & Regulatory Challenges to Combined Heat & Power

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)?

CEC staff paper CEC-200-2012-005 identified additional factors that remain an issue for SoCalGas customers considering CHP:

- **Working With Local Air Quality Management Districts**
- **Cap and Trade**
- **Interconnection**
- **Nonbypassable and Departing Load Charges**
- **Standby and Demand Charges**
- **Metering requirements for small CHP customers**
- **Net Energy Metering concerns for small CHP customers**
- **Project financing**
- **Utility concerns**
- **Feed in tariffs**

Through market research on customers in the under 20 MW CHP market, SoCalGas has identified high upfront costs and apprehension over operating energy equipment as the significant factors. Rate of return, longer term expenses and incentive sunset dates, which are not core to the business, are also important considerations.

As indicated by the stagnant adoption rate for CHP in California, the impact of these economic factors outweighs the large spark spread between relatively high electric rates[3] and low natural gas prices in California.

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

   Departing load charges (DLC's) negatively impact the Net Present Value of the investment by limiting the return on efficiency gains. According to a recent ICF study[4], DLC's can consume up to 36% of annual savings that could be realized.

[3] California has the 5th highest average industrial electric rate and the 3rd highest average commercial electric rate in the continental US per the EIA Average Retail Price of Electricity to Ultimate Customers by End-Use Sector http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_6_a

[4] Ken Darrow and Anne Hampson, ICF International, Inc. 2013. The Effect of Departing Load Charges on the Costs and Benefits of Combined Heat and Power

a. How do these impacts compare to the net impacts of CHP generation on ratepayers?

This is a key area for study and transparency. DLC's are made up primarily of PPPS charges that cogenerators do not get to utilize because they are generating despite the fact that the customer has invested in the generation technology.

b. What analyses and/or studies are needed to fully quantify CHP impacts?

Studies should focus on what level of departing load/standby charges are appropriate given the ratepayer benefits of CHP. Analyses concerning what the actual GHG impacts are, especially in areas of the grid identified as needing help, are also needed. Studies should also identify the best industrial candidates in those areas as well as the technologies that would work best. A study in which both electric utilities and CHP representatives agree to terms and focus on an area where a common cause, like how CHP would provide positive impacts in grid-constrained areas, would also be beneficial.

Additional studies could quantify additional CHP benefits mentioned previously: decreased congestion and increased system reliability; greater resource adequacy; improved stability and power quality including VAR support; T&D and capacity investment deferrals and reduced electricity supply costs resulting from decreased demand; and increased economic productivity and investment for host sites resulting in higher employment and economic growth.

3. Are exit fee allocations that continue indefinitely, without transition or restriction, appropriate for CHP facilities? If not, how should exit fees be allocated over time?

   All of this needs to be clear so that the financial implications are apparent over time. Additional analysis and oversight should be implemented to ensure exit fees are fair. The appropriateness of the charges, from a term, magnitude, and structure standpoint need to be analyzed by a neutral party with full transparency. Disclosure of exactly how those fees are utilized now and what the impact of their loss would be should also be evaluated.

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.

   SoCalGas is aware of challenges faced by specific customers with regard to interconnection inconsistencies, however, due to customer confidentiality concerns SoCalGas cannot provide specific customer information at this time.

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

   The interconnection process creates uncertainty and risk from a CHP customer standpoint as they make the costs and project timeline unpredictable. There is a need for regulatory clarity and consistency on interconnection process with firm deadline and cost predictability.

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?

      Yes, although given the time required to have a project approved under AB1613 (3-6 years), the business case to determine project feasibility will surely have changed.

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

      It would greatly increase the likelihood of project installation and power could be exported to the grid with a revenue stream. Given the problems around getting a project approved under AB1613, consideration of AB1613 is a non-factor in project development.

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

      The electric utilities do not have enough of an incentive to sign customers up to this program. SCG's customers have commented on the difficulties of getting their system in the program. One of our customers installed an extremely complex and unique system but the biggest challenge was obtaining permission to sell electricity to the grid. Customers have said: "Be prepared for how difficult this is going to be" "Go into it knowing you can't set the timeline and you don't know the cost" "There has been no shortage of red tape to cut, reams of paperwork to navigate and countless meetings to get us to this stage".

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

      Customers need more assistance in navigating the program's requirements and should have a better indication of the cost and time required to become enrolled in AB1613.

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 Resource Board's Scoping Plan for AB 32 (6.7 $MMTCO_2E$ annual emissions reduction by 2020)?

   Yes, the Combined Heat and Power Policy Analysis and 2011-2030 Market Assessment[5] identified significant technical potential for CHP in California far above both goals:

[5] Hedman, Bruce, Ken Darrow, Eric Wong, and Anne Hampson, ICF International, Inc. 2012. Combined Heat and Power: 2011-2030 Market Assessment. California Energy Commission. CEC-200-2012-002rev2

Market Type / Size Category	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW	Total
Remaining Technical Potential in Existing Facilities						
Industrial -- On-site	688	375	1,042	818	385	3,309
Commercial, Institutional, Government, Multifamily -- On-site	2,078	846	1,650	929	447	5,950
Export	0	0	286	901	3,847	5,034
Total – Existing Facilities	2,766	1,221	2,987	2,648	4,679	14,293

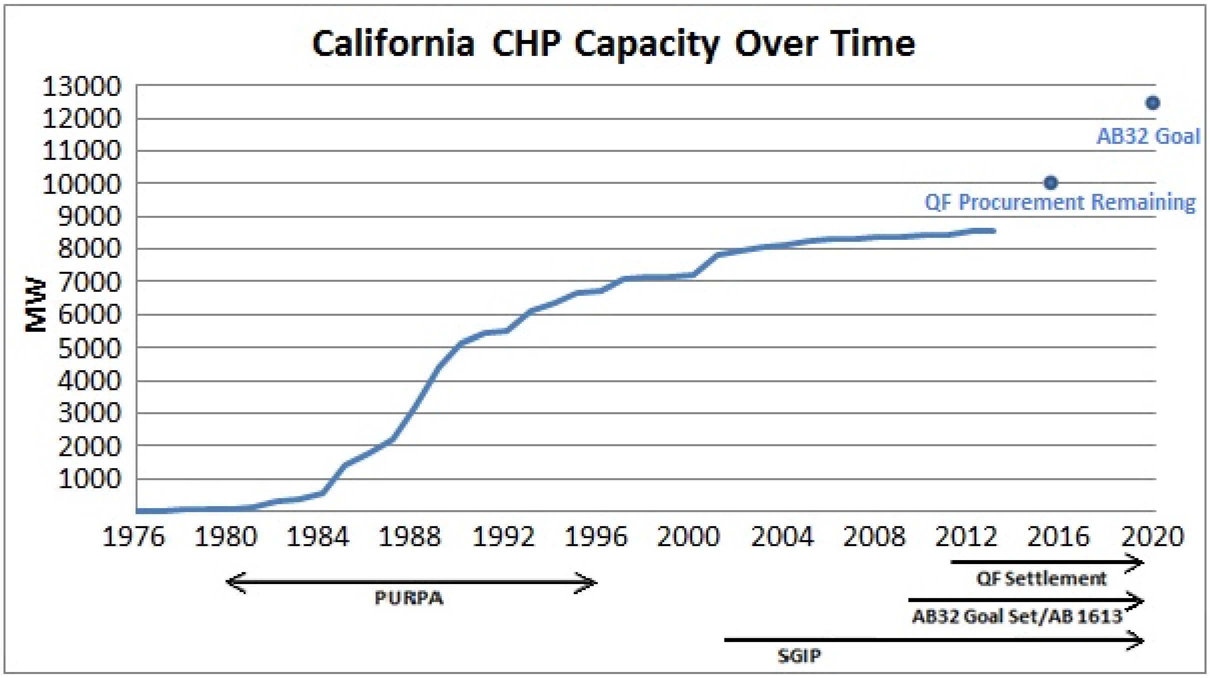
This report also contained a market penetration forecast with the medium case nearing the AB32 goal and the high case nearing the Governor's Clean Energy Jobs Plan:

2011 Scenarios	Cumulative New CHP Market Penetration, MW				
	2011	2015	2020	2025	2030
Base Case	123	617	1,499	1,817	1,888
Medium Case	233	1,165	3,013	3,533	3,629
High Case	340	1,700	4,865	5,894	6,108

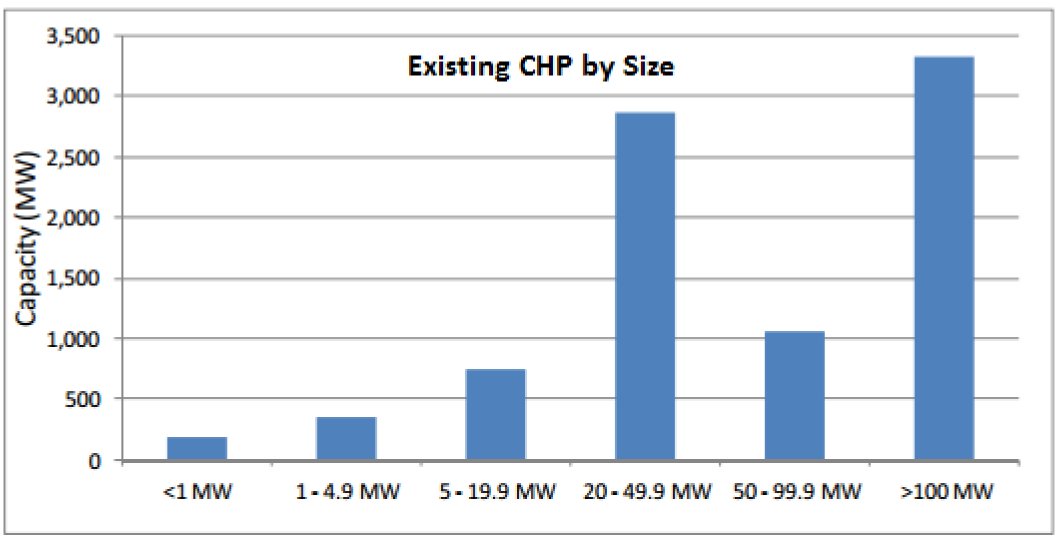
Furthermore, SoCalGas customers show a continued interest in CHP.

2. How should the State meet these goals?
According to the ICF installation database, from the beginning of 2010 to the beginning of 2013 a mere 152 MWs of CHP has been installed in the state. This rate of 50 MW per year falls behind ICF's base case scenario which used 'business as usual' assumptions.

Despite the existence of several programs designed to increase the amount of CHP in state and low gas prices, adoption has been stagnant:



It is worth noting approximately 15%[6] of CHP systems installed in state are below 20 MW in size, however, approximately 70% of CHP technical potential resides in the below 20MW market.



Source: ICF CHP Installation Database.

- **The State should focus on resolving or mitigating the barriers identified by the CEC and mentioned in section II item 1 in order to help meet the state goals**

- **Additional incentive programs may be warranted due to the lack of market stimulation under current programs and the low price of natural gas**

- **New business models should be implemented including direct utility ownership of CHP assets**

[6] IBID.

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 response

4. Do the eligibility requirements of existing CHP programs align with market needs? If not, what changes are needed to stimulate market participation?
   No response

IV. Technology Innovation to Overcome Combined Heat & Power 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)?

   Micro CHP: The Ene-Farm program in Japan promotes the adoption of residential micro CHP fuel cell units. 34,000 Ene-Farm units have been installed in Japan by the end of 2012. The goal is to have 5.3 million units installed by 2030.[7] Gas utility involvement has been crucial for the success of this program and Japanese gas utilities have been involved in technology development, financing, marketing, and distribution.

   Microgrids: Defined as a group of interconnected loads and distributed energy resources with clearly defined electrical boundaries that act as a single controllable entity with respect to the grid and can connect and disconnect from the grid to enable it to operate in both grid-connected or island mode. CHP can be utilized in a microgrid as a source of both electricity and heat.

   Emission Control Technology: Advancements in emission control technology help increase the GHG benefits of CHP. These technologies should be integrated into preapproved packaged units.

   Interconnection: Interconnection equipment can be standardized and integrated into packaged units.

   Biogas: Advances in anaerobic digestion, biogas cleanup, and biomaterial collection will increase the GHG benefits of CHP. CHP systems are often used to power biogas projects and can provide synergies in advancing the utilization of bio resources.

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

   In the near term RD&D should prioritize standardized utility endorsed interconnection equipment

[7] http://www.fuelcellinsider.org/?p=1388, http://altenergymag.com/emagazine/2013/10/residential-scale-power-generation-/2162

integrated into packaged units; emission control devices to improve GHG benefits; and a streamlined certification process for getting equipment packages permitted through air quality management districts. Packages could be pre-qualified for emissions and interconnection. Advances in this area would have the largest impact on CHP adoption particularly because they are applicable to systems in the below 20 MW market.

V. Electrical Generation Unit and Reference Boiler Efficiency

Double Benchmark accounting is a methodology for determining fuel savings when a CHP system displaces thermal and electrical energy that would have been generated separately. This method requires energy conversion efficiencies for the displaced thermal and electrical resources, usually given in the form of a reference boiler efficiency and an effective grid heat rate. Determining these efficiencies is a complex problem, and the best method for doing so remains an open question.

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)?

   It should not be necessary to categorize electric and thermal generation separately. It should be realized and understood that CHP technologies and applications are determined through site specific parameters and the cost effectiveness of the application. Economic factors determine if the fuel savings of CHP can overcome the inherent barriers/risks associated with CHP. To the extent CHP is cost-effective, fuel use is reduced, making a reference to double benchmarks unnecessary.

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)?

   A key factor should be what load the CHP unit is displacing. This should be least efficient load following and peaking fossil generator in the CHP unit's service territory. Operational characteristics are key because load following equipment will not perform at the optimal efficiency. Consideration of this fact should be made. Overall grid interactions between all supply sources, demand, DR, and EE must be taken into account.

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)?

   Establish a fair efficiency value that would accommodate the variability of boiler load while in operation. The overall efficiency will be less than 80% for steam boilers.

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?

   Metering thermal output would add additional cost to operating CHP equipment and add to the financial burden for CHP customers. The SGIP requires metering of thermal output to determine

system efficiency (which is reported to the state); however the SGIP requires the use of expensive utility grade meters regardless of project size when most thermal loads can be determined utilizing far less expensive equipment.

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.
   The simple extrapolation (regression analysis) of historical technological improvements in the efficiency of new Combustion Turbines and Combined Cycles from 2004 through 2013 will miss the major changes in the operation of these new resources, especially as more variable energy resources are integrated into the grid. Operational changes that will increase the number of starts and shutdowns will reduce the number of hours units will operate at their preferred operating points. Operating in this manner will significantly increase the use of 'peaking' resources relative to the current use of 'load following' resources. As a result, the share of energy allocated to 'peaking' resources will increase from the current 2.5 percent used in the staff's methodology.

2. Is the Energy Commission staff's approach to the treatment of renewable energy appropriate? If not, please explain.
   AB327 implies that the 33% RPS is a floor; not a cap. As such, <u>increases in behind the meter</u> <u>CHP will not reduce RPS capacity requirements</u> on a one MW to one MW basis. Furthermore, the 2007 energy action plan identified CHP as a preferred resource in the "loading order" following cost-effective energy efficiency, demand response, and renewable energy systems. Therefore <u>CHP will not displace any renewable generation</u>.

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

   Programs are usually created to meet specific goals. Creating a methodology that could be applied across programs will not necessarily take the specific goals of a program into account. At most, the CEC methodology should be used to supplement exiting program evaluations, not replace them.

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.
   Please see answer to 1.

5. Is the use of a single, state-wide heat rate projection appropriate? If not, please explain and propose an alternative.
   Yes, heat rates depend on the unit's technology, age, and how the unit is operated. In essence, heat rates are unit-specific but the variation in heat rates does not justify the complexity of a unit-specific methodology. Using an energy-weighted average of the units for each of the two categories will provide a relatively stable average heat rate for the state.

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

Yes, as long as each category is representative of how the units are actually operated. New quick-start combustion turbines used specifically for ramping may require the creation of third category.

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

   Not clear on how the methodology deals with imported electricity.

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

   This is a CAISO or electric utility question.

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

   No. Using the technological capabilities as the floor for Combustion Turbines and Combined Cycles heat rates are too low because the units will not be operated at required levels for the majority of their operating times.