STATE OF CALIFORNIA

ENERGY RESOURCES
CONSERVATION AND DEVELOPMENT COMMISSION

In the matter of: *2014 Combined Heat and Power Staff Workshop*	Docket 14-CHP-1 WORKSHOP RE Combined Heat and Power

COMMENTS OF THE ENERGY PRODUCERS AND USERS COALITION AND THE COGENERATION ASSOCIATION OF CALIFORNIA ON THE CHP QUESTIONS FOR STAKEHOLDERS

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On July 14, 2014, the California Energy Commission staff held a long needed workshop on California Combined Heat and Power resources. The workshop highlighted the continuing failure of State-administered plans designed to promote the retention of existing and development of new CHP facilities. Participants repeated the longstanding refrain that despite grand positive statements of state policy favoring CHP, implementation of procurement programs administered by the states' Investor-Owned Utilities has not addressed longstanding barriers to entry. Additionally, the workshop assessed and repudiated a suspect analysis initiated by Pacific Gas and Electric Company, which distorted and challenged the benefits of CHP to reduce greenhouse gas emissions relative to separate heat and power options. Finally, staff provided an analytical proposal to identify marginal fuel and emission profiles for the future California grid to aid in the analysis of the benefits of CHP resources.

The workshop notice seeks comments on a wide range of specific questions related to the parties' presentations and the assessment of GHG resource development. This submission by the Energy Producers and Users Coalition (EPUC)[1] and the Cogeneration Association of California (CAC),[2] respond to the questions presented.

REPLY TO SPECIFIC QUESTIONS

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 joint presentation at the workshop from EPUC, CAC and the California Cogeneration Counsel identified multiple benefits from CHP for the California electric grid. The benefits identified in the joint presentation include: (a) avoided transmission and distribution capacity costs; (b) GHG emission reductions; (c) market price mitigation; and (d) system reliability. In addition, CHP provides local, in-state generating capacity; reduces burdens on the State's power grid; increases system reliability; reduces the State's overall consumption of natural gas; increases thermal power generation efficiencies; and provides environmental benefits. Not only are the benefits which existing CHP projects have delivered to California significant, many of these benefits are quantifiable.

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[1] EPUC is an ad hoc group representing the electric end use and customer generation interests of the following companies: Aera Energy LLC, Chevron U.S.A. Inc., Phillips 66 Company, Shell Oil Products US, Tesoro Refining & Marketing Company LLC, THUMS Long Beach Company, and Occidental of Elk Hills, Inc.

[2] CAC represents the combined heat and power and cogeneration operation interests of the following entities: Coalinga Cogeneration Company, Mid-Set Cogeneration Company, Kern River Cogeneration Company, Sycamore Cogeneration Company, Sargent Canyon Cogeneration Company, Salinas River Cogeneration Company, Midway Sunset Cogeneration Company and Watson Cogeneration Company.

a. CHP Increases System Reliability

b. CHP Provides Local Reliability

c. CHP Reduces GHG Intensity of the Utility Portfolio

d. CHP Supports the Grid in Emergency Conditions

e. CHP Substitutes Private Capital for Ratepayer Capital

Attracting Private Capital. From an electric utility ratepayer perspective, private capital typically funds development and operation of CHP generation and interconnection projects. In contrast, ratepayer-backed utility capital typically funds large central generation power plants and transmission or distribution infrastructure development and operation. In California, these significant private capital investments in CHP serve the grid in material ways.

Energy Efficiency*.* CHP supplies reliable and cost-effective generation for ratepayers while also satisfying industrial and commercial thermal process requirements. This two-for-one use of fuel to produce two useful products – electricity and thermal power – from the use of a single fuel is the hallmark of cogeneration. When used efficiently, this process provides material benefits over separate electric power plant production and thermal boiler operations.

Reliability and Security. Many CHP facilities are located in secure industrial facilities or near electric energy-consuming entities (load centers), thus enhancing the reliability and security of the ratepayer, electric utility, CAISO and State's electric energy supply.

State Infrastructure Economic Benefits. Moreover, CHP provides economic benefits for the California economy by enabling businesses to manage energy costs that translate into more jobs and electric utility customers.

Existing CHP has historically provided a significant amount of the total installed capacity on the utilities' electric systems. This capacity is comprised of multiple smaller generating units in comparison to large central station utility generation facilities. The CHP capacity is located within California at multiple distributed sites throughout the service areas of these utility systems. This CHP capacity is demonstrably reliable from any historical perspective. Even Southern California Edison Company, a staunch opponent of the encouragement of CHP resources, acknowledged that SCE's total CHP facilities under contract operated at an average 89% capacity factor.[3] This operating statistic compares very favorably with that of other baseload-type resources. For example, the annual average capacity factor for large PWR nuclear units comparable in size to SONGS as reported to the North American Electric Reliability Council for the period 2009 through 2013 was 87.5%.

From a system reliability standpoint, a system comprised of many small generating units is more reliable than a system with fewer large generating units. For example, two 250 MW units each with a 10% forced outage rate have a combined 1.0×10^{-2} probability of having 500 MW out of service (*i.e.*, 0.10^2) or one chance in 100. On the other hand, ten 50 MW units each with a 10% forced outage rate have only a combined 1.0×10^{-10} probability of having 500 MW out of service (*i.e.*, 0.10^{10}) or one

[3] See, SCE's Long-Term Procurement Plan Testimony, Volume 1, before the CPUC in A.04-04-003, p. 61, Table IV-10 Annual Average Capacity Factors by Technology (including Cogeneration), July 9, 2004.

chance in 10 million. Accordingly, a generation resource mix comprising many small generating facilities enhances the reliability of the California generation supply vis-à-vis the same level of capacity reflected in a fewer number of larger generating units. Existing CHP projects are of various sizes, but the typically larger facilities are comprised of independent CT/HRSG trains that range in size from 10 MW to 85 MW. In comparison, the more efficient combined cycle utility power projects have power blocks that approach several hundred megawatts in size (depending on the CT to ST configurations).

Another benefit of existing CHP (as well as new CHP) is the ability to keep essential and critical industry operating during natural disasters or system emergencies. For example, a refinery located in a major load center employing CHP as a source of both electric and thermal energy may sustain operations in the event of a sudden loss of electrical supply from the electric utility. If that refinery is the major source of fuel for a major airport a disruption in transportation fuels can cause major problems. The ability of the State to successfully cope with the electrical disruption in this circumstance is a major benefit of CHP reliability. Moreover, the reliance on CHP by such facilities allows for the management of an orderly and safe shutdown of operations resulting from a loss of electric power supply. This feature enhances public safety in comparison to a sudden and unannounced loss of electrical supply from the interconnected electric utility.

CHP projects are located in proximity to the thermal and electric loads of their thermal hosts. In many cases, these industrial sites are also within or near utility load centers. The CHP operation and location reduces the amount of electrical power that needs to flow over the utility grid (*i.e.*, the transmission and distribution system) to serve the host and utility load. Accordingly, existing QF cogeneration reduces the losses associated with moving power over the wires connecting the thermal host load to more remotely located generation. For example, if the losses for power flowing over the utilities' wires are 7.0%, 107 MWa of generation are required for every 100 MWa of energy metered at the location where the energy is consumed. On the other hand, CHP serving that same 100 MWa load requires only 100 MWa; thus the additional 7 MWa of generation required to deliver power from remote resources is saved and available to serve other customers.

The use of CHP (on-site or both on-site and export) in a geographical area that relies heavily on the transmission system can avoid transmission expansion costs and relieve transmission congestion. As a result, existing QF cogeneration enhances the available supply of generation system-wide and relieves the loading (and associated costs) on the transmission and distribution system. These geographical areas can be both remote to major load centers or comprised of major load centers depending on the transmission configuration supplying the geographical area.

Utility customers that employ existing CHP technologies reduce the overall demand for natural gas because of the improved thermal efficiencies associated with cogeneration. This occurs by replacing less efficient boilers consuming natural gas with more efficient cogeneration equipment that produces both electricity and thermal output using the same input fuel. Thus, there is a reduction in overall consumption of natural gas in the State when CHP simultaneously uses a single fuel to provide two needed power supplies – thermal and electric. As an example, the applications of CHP to enhanced oil recovery (EOR) operations are demonstrably beneficial. A large existing CHP EOR facility can supply both thermal and electrical energy at an overall efficiency of about 72% on a HHV basis. In comparison, a combine cycle unit operating at a 7,361 Btu/kWh average heat rate is only about 46% efficient on an HHV basis. CHP employing new combustion turbine technology and implementing duct firing to meet thermal requirements can reach overall efficiencies in the range of 80% on an HHV (*i.e.,* a 74% better efficient use of natural gas than the heat rate of 7,361 Btu/kWh from a combined cycle facility[4]). Yet absent a material change in implementation actions related to well established State policies and objectives regarding the maintenance of existing and the development of new CHP, these benefits remain unfulfilled.

Certain existing CHP facilities, such as those sited at petroleum refineries, increase fuel efficiency by consuming waste fuels from the manufacturing process. These "waste" fuels can be productively used by a CHP operation. The use of waste fuels is not the only efficiency benefit of CHP. Waste heat recovery is another benefit relative to CHP fuel savings for the State.

A CEC published CHP report estimated that the total energy savings associated with CHP waste heat recovery in 2017 is projected as about 150 Trillion BTUs.[5] Capturing waste heat for CHP is an option for bottoming cycle facilities because of industrial processes, or a direct product of CHP topping cycle facilities. In terms of natural gas usage, 150 Trillion BTUs is approximately equivalent to the annual fuel consumption of a 2,900 MW base-loaded power plant that operates with a heat rate of 7,361 Btu/kWh and at an 80% capacity factor. The CEC report estimated that existing

[4] EIA reported filing of the 2013 SCE Mountainview Generating Station annual heat rate in HHV.
[5] Market Assessment of Combined Heat and Power in the State of California (Report Date: July 1999), California Energy Commission Consultant Report, October 2000.

CHP reduces in-state NOx emissions by over 7,600 tons annually and reduced CO2 emissions of about 26 million tons per year on a regional basis. The GHG saving for a new CHP operating at an 80% HHV efficiency are significant in comparison to a double benchmark based on an 80% boiler efficiency and the incremental system electric heat rate.[6] The annual average LMP-based incremental equivalent natural gas burner tip heat rate is 8,438 MMBtu/MWh based on the previously described criteria. The annual CO2 saving in MT/MW of new CHP capacity would be slightly less than 2,000 MT of CO2 saved per year for every 1 MW of 80% efficient CHP installed. In short, there are material GHG benefits to be derived from CHP, but these are only one component of a wide range of benefits from this form of generation to the State.

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

Transmission grid operation benefits from generation whether from CHP or conventional generation in three major ways.

a. Mitigate temporary transmission constraints.

b. Provide Reactive Power for voltage support.

c. Supply local capacity in support of transmission contingencies.

Grid operators also seek dispatchability to support integration of renewable resources mandated by the State.

1) CHP Mitigates Temporary Transmission Constraints

CHP can provide temporary transmission constraint mitigation benefits via dispersed location of generation in general, and, particularly, in geographic areas where

[6] The heat rate for this comparison is from 2013 annual SP-15 hourly day ahead LMP data published by the CAISO, SCE monthly SRAC VOM and burner tip natural gas prices and a $12/MT GHG allowance price.

known transmission constraints exist. For example, a utility with multiple transmission planning areas that are operationally independent may have existing and potential new CHP facilities located within that planning area. Temporary transmission constraints such as over loading a transmission line under unusual operation conditions can be mitigated if generation in the area can be increased to relieve the loading on the transmission line. CHP facilities can temporally increase generation to assist in the mitigation of a transmission constraint.

2) CHP Provides Voltage Support

CHP projects of any size employ synchronous generators that are capable of supplying or absorbing reactive power. Accordingly, CHP is a valuable benefit for voltage support to grid operators, in part due to the CHP design characteristics and dispersed locations.

Beyond the temporary transmission constraint mitigation benefits that, in part, rely on CHPs ability to increase generation output for a temporary period on an infrequent basis, there are additional benefits from CHP distributed generation capacity. Local capacity (CHP distributed capacity) also supports stability for transmission contingencies. The grid operator can rely on both generator location and upon generation that is typically on line and operating – features of a well-established CHP program. CHP is of particular benefit because of the inherent reliability of the operation tied of manufacturing and industrial host needs, and the baseload operating characteristics of CHP. In transmission planning, the “planned for” contingencies should not cause other elements of the system to fall below accepted standard frequencies, harmonics or operating standards. Because CHP is baseload and reliable, the transmission operators are provided a stable and reliable level of generation with relatively assured capacity for support during contingency events.

3) CHP Provides Local Grid Support

Another benefit of distributed CHP resources is the provision of reliable electric service to customers outside load centers or remote from utility generation. The overall economics or distant from major load centers may not support utility or merchant plant installation in a transmission planning area that could benefit from generation. On the other hand, CHP is a function of industrial requirements and an industrial CHP facility could be economically feasible to be located where an otherwise transmission upgrade or new line would be required to deal with constraints or contingency concerns.

4) Dispatchability Is Not A Natural CHP Attribute For Thermally Matched CHP Facilities

The current complaint about CHP from IOU interests center on the fact that the facilities are "baseload" and not dispatchable. While baseload CHP provides a benefit in terms of reliability, the IOUs view this attribute as a negative when integration of intermittent renewable resources are considered. In addition, IOU procurement often leads to peaker facilities that would be directly displaced by CHP baseload operations.

Much of the current "CHP" procurement that occurred under the CHP Settlement is in fact the procurement of CHP facilities formerly challenged by IOU interests as "PURPA machines." The characteristics of such previously distained PURPA operations were the lack of a "real" thermal host, or need of thermal output. Today these facilities are "flexible hosts" or Resource Adequacy-only CHP, or Utility Prescheduled Facilities whose change of operations is due to the lack of thermal demand or the substitution of thermal demands by boiler installations. These facilities have become the darlings of IOU procurement under the CPUC QF/CHP Program Settlement, rather than baseload CHP operations. While desirable for other reasons, these facilities are not conventional CHP with high, baseload demand for thermal energy.

State policies and successful implementation plans should secure baseload CHP for their efficiency and benefits. The current implementation of the CPUC program has been somewhat undermined by the procurement of non-baseload CHP resources. Baseload CHP resources remain un-favored by IOU procurement choices and implementation actions under the CPUC CHP Program. The IOUs call for displaceable, dispatchable CHP; but that is an oxymoron. Well-established and efficient CHP is a base load operation serving the thermal demands of an industrial or manufacturing host. Displacement or dispatchability of these resources, now a common standard to secure an IOU contract, should not be a requirement for procurement. Just like other resources that the State supports for public policy reasons, *e.g.*, renewables, dispatch of CHP resources is an artificial barrier to entry. State policy and IOU procurement should reject or temper dispatch requirements for thermally matched CHP resources, recognizing that some level of baseload generation will always be needed for a stable grid. The preferred-resource CHP facilities are baseload operations to the extent they meet thermal demand from thermal hosts. These “heat sink” sites should be retaining existing and provide meaningful opportunities for developing new baseload, thermally matched CHP resources.

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?**

The availability of current data relative to CHP resources under the CPUC QF/CHP Program is inadequate. Regulators and stakeholders alike do not have readily available or timely access to IOU data related to CHP to allow evaluation of the success or failures of the State's CHP programs. Fundamental data are missing from the current utility reports on CHP status, like termination dates of existing agreements to forecast CHP resources, or explanations regarding the loss or termination of CHP projects. Information regarding the calculation of GHG emission reductions from individual facilities while utilized by the IOUs to determine meeting objectives relative to CARB's Scoping Plan for CHP, is not available. The timeliness of utility reporting even of the limited data provided, on a semiannual basis, regarding procurement actions and failed CHP operations is too infrequent to be useful.

In this age of web-available information, there is no reason the IOUs should not dynamically provide updated information on any CHP facility as soon as the information is available. For example, the CEC could direct IOUs to provide current updates upon certain events, *e.g.*, a newly executed contract or amendment, a notice of termination by existing facilities, the performance of capacity demonstration tests and calculations of GHG emission reductions or allowance credits provided by the IOU. There is a template contemplated for key sources of data information imbedded in the CPUC's QF/CHP Program Settlement Term Sheet (see Section 8). The regular and active update of that form of information from each IOU on respective web sites would enable regulators and stakeholders to evaluate the status of the State's CHP program for existing, repowered or new facilities.

A related issue to the adequate and timely disclosure of information to assess the CHP Program is the longstanding concern of the proper disclosure of IOU procurement information. In 2006, the CPUC issued a decision (D.06-06-066) to address the treatment of information deemed "confidential" relative to public utility data, documents and information. One feature of that decision found that utility contracts like those executed for CHP resources would not be subject to confidential treatment after three years' time. However, despite repeated efforts, this documentation is unavailable. The lack of regulatory enforcement and IOU compliance with these disclosure conditions of procurement contracts stands as a data barrier. There is no basis for the failure to immediately address this issue. The IOUs post on their web sites a listing with active links to contracts for the renewable program that is current and regularly updated. Regulators should compel the same open disclosure treatment for other procurement contracts; particularly CHP contracts. These unenforced confidentiality rules that continue to secret utility load and resource data frustrates the ability for CHP parties to assess the available market and IOU-accepted contract conditions. This lack of public data hinders the objectives of retaining and securing CHP resources, and could be easily remedied by the CEC or the CPUC.

A data template for IOU CHP procurement information is available from Section 8 of the QF/CHP Program Settlement. The following paragraphs provide both a limitation on the disclosure of certain specific project data, as well as a list of relevant IOU data for CHP program evaluations.

First, the limitation – individual CHP project on-site electric and thermal energy operational data is commercially sensitive and must be kept confidential. Any use of such commercially sensitive data must be restricted comparative calculations where the result is structured to assure confidentially and prohibit reverse engineering of the calculation to obtain individual customer data approximations.

With respect to utility data, the following is a sample of the type of data that would be useful:

1. Most recent calendar year utility generation-related rate base aggregated in the following categories:

    a) Nuclear
    b) Coal
    c) Combined-Cycle
    d) Combustion Turbine
    e) Hydro
    f) Other

2. Most recent GRC authorized return on utility owned generation resource rate base.

3. Most recent calendar year actual return on utility owned generation resource rate base.

4. The most recent calendar year total generation-related revenue requirement (including all balancing accounts), aggregated in the following categories:

    a) Nuclear
    b) Coal
    c) Combined-Cycle
    d) Combustion Turbine;
    e) Hydro
    f) Other Utility Owned Resources
    g) RPS Purchases
    h) CAISO Day-Ahead Market Purchases
    i) CAISO Real-Time Market Purchases
    j) Bilateral Tolling Purchases (including utility provided fuel)
    k) Bilateral/RFO RA Purchases
    l) Bilateral/RFO Capacity and Energy Purchased (non-CHP)
    m) Bilateral/RFO CHP Purchases

n) Any Other Generation-related Procurement

5. The most recent calendar year total generation-related generation output in MWh aggregated in the following categories:

    a) Nuclear
    b) Coal
    c) Combined-Cycle
    d) Combustion Turbine
    e) Hydro
    f) Other Utility Owned Resources
    g) RPS Purchases
    h) CAISO Day-Ahead Market Purchases
    i) CAISO Real-Time Market Purchases
    j) Bilateral Tolling Purchases (including utility provided fuel)
    k) Bilateral/RFO RA Purchases
    l) Bilateral/RFO Capacity and Energy Purchased (non-CHP)
    m) Bilateral/RFO CHP Purchases
    n) Any Other Generation-related Procurement

6. Most recent calendar month load/resource balance showing the following items by month:

    a) Actual Peak Load obligation
    b) Actual total Capacity Procured by categories:

        i. Utility Owned Generation Resources
        ii. RPS Portfolio Capacity
        iii. CHP Portfolio Capacity
        iv. Bilateral/RFO Capacity (non-RPS/CHP)
        v. Other Capacity (describe)

    c) Actual Reserves Available at Time of Peak Load
    d) Actual Energy Requirement in MWh
    e) Actual Sources of Energy in MWh by categories:

        i. Utility Owned Generation Resources
        ii. RPS Portfolio Capacity
        iii. CHP Portfolio Capacity
        iv. Bilateral/RFO Capacity (non-RPS/CHP)
        v. Other Capacity (describe)

7. Fuel type of the last dispatched unit for each hour of the most recent 36 month time period (i.e., the fuel type for the marginal resource)

8. System lambda for each hour of the most recent 36 months

9. The marginal resource type (i.e., CT, combined cycle, etc.)

10. The total rated capacity of the utilities' RPS portfolio

11. The percentage of the total rated RPS portfolio capacity that is eligible to be counted toward the utilities firm capacity for resource adequacy purposes

12. The amount of capacity that must be procured by the utility to firm the RPS energy

13. The total fixed costs – Capital (including but not limited to "return of" and "return on" investment and income taxes), Insurance, fixed O&M, general plant and administrative cost allocation, and ad valorem taxes) express in $/kW-year attributable to RPS firming capacity

14. Identification of area with transmission constraints, voltage support issues, and potential need for generation to support transmission

A final observation about available IOU published data relates to San Diego Gas and Electric Company's semiannual report that includes the status of CHP projects.[7] Uniquely among the IOUs, SDG&E provides a list of terminated CHP projects and contracts since 1995. The listing is both informative and disturbing to reveal the loss of CHP resources over the course of time. As noted, the other IOUs do not publish this information, yet the information is illuminating about the health of the CHP program and procurement. The SDG&E model of reported terminated projects could become a required list from all IOUs along with an important enhancement for each facility – did the project cease operations, shut down or return to utility service?

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

The CEC should secure the data and in a collaborative process determine what information is properly available publicly. For such data, it is appropriate to make it readily available through active web updates by each IOU. For materials deemed

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[7] See the "Terminated" tab in the SDG&E Qualifying Facility Cogeneration and Small Power Production Report - Jan 2014 - Jun 2014, http://www2.sdge.com/srac/Jan_Jun_2014.mht.

market sensitive or commercially sensitive, there should be a means to allow vetting of such concerns and the reliance on protective orders to facilitate the analysis and masking of such data for public presentations. If there are real concerns over trade secrets or information that needs protection, FERC's well establish protective orders made applicable to stakeholders and CHP parties affords an available option for protected disclosure.

There is no basis or reason to continue ignoring the lack of systematic data for CHP resources to demonstrate even partial viability of the CHP program or the success of an IOU-administered CHP procurement program. The CEC could lead the critical role in facilitating appropriate information to assess, on a realistic and timely basis, CHP procurement consistent with State policies and objectives.

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

Developing a study without having full knowledge of the availability of consistent data across all resources is, at best, problematic. Nevertheless, a study evaluating the benefits of CHP in comparison to other resources should reflect a methodology that, at a minimum, computes the annual costs and benefits of each resource and assess net benefits on a per unit metric as well as on a total dollar basis. The benefits of CHP must reflect the sequential fuel use characteristic of CHP whereby the same fuel produces both electrical energy and thermal energy. Moreover, the differences in reliability and dependability should be reflected (*e.g.*, wind, solar and hydroelectric plants produce electricity intermittently and therefore generate additional system balancing and cycling costs that have to be taken into account).

As a first step in developing a meaningful comprehensive CHP benefit study, the Commission may want to devote initial effort on the means to obtain the consistent data required for the CHP study.

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?**

Please refer to the benefits and cost responses to questions in Sections I.1 and I.2.

II. Economic Barriers and 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)?**

Decisions for developers of large CHP facilities evaluate the Net Present Value (NPV) of the CHP investment compared with the NPV of separate heat and power alternative (boiler for thermal and purchased electric power). Project NPVs take into account all cost and revenue streams associated with the thermal and electric power production and use. Many factors, including natural gas fuel price forecasts, the cost of carbon allowances, and exit fees influence NPV. Before financing issues are addressed, a developer of CHP must work through challenging engineering and feasibility analysis, the prospect of difficult and long duration permitting processes and the prospect of material and disruptive changes in State programs and regulations.

Certainty and consistency of public policy with respect to capital investment recovery is a critical factor. The availability and protection of realistic pricing and reasonable commercial contract terms and conditions are essential. These features provide necessary assurance of sufficient electric revenue to compensate for additional capital investment required for CHP investment. This investment requires reasonable assurances for capital investment for the project, but also the ongoing recovery of anticipated major equipment overhaul costs and ongoing operational costs.

Another key factor is certainty that operational restrictions and/or obligations will facilitate the manufacturing or industrial host's operations. Curtailment or interruption of required thermal generation, except for system emergencies, renders a host unwilling to support CHP investment.

The unavailability of commercially reasonable power purchase agreements that in actual practice have become one-sided, unilateral in risk allocation and confiscatory have continued to shrink the appetite of thermal hosts to engage in CHP development. Contract provisions and regulatory risks associated with the CHP in comparison with separate heat and power options are significant factors relative to CHP development.

One of the most critical economic factors is the challenge faced by CHP in securing reasonably priced contracts to sustain operations or to develop new facilities. The CEC need only review the MWs of new CHP installed since the inception of the CPUC's QF/CHP Program Settlement to appreciate the program shortfalls. Another indicator is the number of and size of the permits issued for new CHP operations with the CED; once again, the lack of permits reveal that the State's CHP program is failing.

Current policy, while favorable to CHP, has failed in implementation to encourage the development of CHP in the State. This observation calls to mind that settlements among parties are not substitutes for public policy, nor are they substitutes for obtaining the objectives of public policy.

2. **What impacts do departing load charges have on the viability of developing new CHP resources? In general, reduce the CHP economics and discourage development and for some project eliminate the CHP option entirely.**

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

The net impacts on ratepayers is relatively simple to assess. The impact of 600 MW of departing load on the average residential class annual revenue is minimal. For example, this amount is less than a $2 per year increase on the SCE system in the cost associated with Public Purpose Program and Nuclear Decommissioning Cost portion of the average revenue.

It is difficult to identify the "net impacts" of departing load charges on CHP generation, and impacts will vary by project. In some cases, however, departing load charges of $15 MWh or more will tip the project's economic analysis against an acceptable project return. Because these projects compete within a corporation for available capital based on return, departing load charges that tip the balance can kill a project.

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

Departing load charges reduce the CHP economics and discourage development of CHP development. These non-bypassable charges or exit fees can increase the return required to justify a new facility so materially that the project becomes uneconomic. Reaching this conclusion does not require delving into the confidential economics of a CHP development. The telling fact is that the economic benefit of a CHP option is to eliminate utility costs and secure reliability. The utility cost elimination is eviscerated by imposing exit fees that serve to treat the departing load to the same costs incurred as if the load stayed on the utility system. Accordingly, exit fees serve as a deterrent to CHP competition with utility supplied generation. In some instances, regulatory authorities have prohibited the application of exit fees to customer-owned generation or self-generation in recognition for the anti-competitive nature of the charges. For example, the Federal Energy Regulatory Commission perhaps said it best in adopting its stranded transmission cost policy in Order 888. FERC stated:

> *this Rule will not insulate a utility from the normal risks of competition, such as self-generation, cogeneration or industrial plant closure, that do not arise from the new availability of nondiscriminatory open access transmission. Any such costs would not constitute stranded costs for the purposes of this Rule.*

From an electrical power perspective, a CHP customer invests significant private capital for an energy efficiency project designed to reduce costs, maximize the efficient use of fuel, and to reduce emissions, including GHG. Moreover, this customer has taken on the long-term risks and obligations associated with the principle costs of electric generation supply. This means the customer no longer has the benefits derived from any allocations from the bundled customer portfolio of generation resources. The long-term nature of this commitment will, in theory, free up existing resource both transmission and generation to serve other customers and avoid the need for the utility to make future capital expenditures or purchases. Furthermore, the CHP generation will provide the benefits discussed in Section I above.

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?

Exit fees should be eliminated for load served by existing CHP, or imposed on load served by new CHP. Consider that some exist fees are designed to support energy efficiency programs. CHP is an energy efficiency program. As such, ironically, CHP is charged as energy efficiency paying for energy efficiency. To the extent Departing Load Charges are imposed, these exit fees should be eliminated after a reasonable period – certainly no longer than a short term planning cycle for utility planning purposes. In addition, a developer of new CHP should be offered the opportunity to make an upfront payment based on then-current charges. However, these continuing accommodations for the imposition of exit fees are suboptimal and erect economic barriers for CHP. Accordingly, the Departing Load Charges should not continue indefinitely for customers employing CHP and should cease to be applicable immediately.

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.**

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

This response addresses both of the questions above. A multitude of examples of challenges and barriers exist, and these barriers have not been overcome.

Regulatory challenges and barriers examples:

- *Increasing generation behind an existing CHP contract.* A significant challenge can be adding additional CHP generating units to sites with existing CHP generating units. It may be difficult or impossible to retain beneficial features for the existing contract rights in negotiating with a utility to permit operation of the new units behind the contract.

- *Interconnection.* Interconnection for CHP is both extraordinarily time consuming and expensive. The studies to assess interconnection have lead times that are simply too long and costs that are daunting for even the largest of developers. Moreover, the pro forma Large Generator Interconnection Agreement does not contemplate a CHP operation, but rather an unbuilt merchant power plant. Neither the CAISO nor the interconnected IOU has any interest in tailoring the agreements for CHP resources.

- *Cap and trade.* Compliance costs and risks arising from the cap and trade program create uncertainty, particularly for exporting CHP facilities.

- *Reasonable negotiations.* Contracting with IOUs for CHP resources is performed in a "black hole" shrouded in secrecy with no avenue of appeal should the IOU decide to simply employ a constant refrain of "no" to CHP offers. Under this process, the IOUs can unilaterally tailor contracts such that there can be little or no balance in the commercial negotiation of these agreements. This provides the IOU with an unfair advantage to the CHP needing a forward contract who can find itself in a take it, or leave it conundrum.

- *CPUC interpretations.* CPUC Energy Division implementation and interpretations of the Settlement conditions reflect Staff's view that the Settlement provides a ceiling on CHP procurement, not a floor. This view is manifested when addressing implementation conditions that would promote procurement or the restriction of unilaterally imposed IOU conditions divergent from the Settlement establish pro forma agreement.

- *Preference for dispatchable capacity.* The reservation of capacity for CHP under the Settlement is expressly to provide a CHP-to-CHP competitive RFO process in light of the failures of all-source bidding RFOs to favor baseload CHP. Yet the procurement of resources under the CPUC Energy Division has resulted in the procurement of the very resources (such as CHP) that rendered the all-source bids meaningless for CHP. RA only resources, an ever expanding transition of CHP resources to UPF operations, the installation of boilers to render hosts "flexible" in the demand for CHP baseload operation are all examples of dispatchable resources "counting" against the CHP Settlement targets.

- *IOU position on pro forma contracts.* The Settlement contemplates the use of a standard pro forma agreement that is subject to modification to account for individual project differences. However, the current process allows the IOUs to dismiss that standard with no timely recourse for the CHP resource needing a contract. For example, an IOU can unilaterally decide that any change – even punctuation - is deemed material.

- *GHG risk challenges in contracts*. A particular example of the problem with contract negotiations is the treatment of GHG compliance risk. GHG compliance is a risk that from a CHP perspective should be a socialized cost spread to all IOU ratepayers. But the IOUs see the transfer of such risks to individual generators as a barrier in light of the uncertainty. Under the Settlement pro forma agreement, the CHP seller is allowed to elect whether the IOU bears the costs of compliance, or the seller bears the risks or a hybrid sharing of such costs proposed. The adopted provisions provide for each CHP resource to submit its terms for GHG recovery in Exhibit S to the pro forma. IOUs have substituted Exhibit S provisions with their own unilateral position on GHG cost and risk allocation to the CHP Seller. Far from a "bilateral" negotiation between equal parties, the CHP has little or no choice but to accept the IOU risk allocation.

- *Jurisdiction.* The IOUs have contested the CPUC's authority under PURPA in implementing the CHP Settlement. They argue that the program is subject to FERC jurisdictional wholesale market pricing scheme rather than the Commission's oversight of avoided cost. The latter will impose regulatory obligations and FERC administrative filing burdens on CHP operations never imposed before.

These are but a few of the observed barriers to entry for CHP resources.

Solutions, while apparent, seem remote, but here are the few options that have worked for the State in the past that warrant reconsideration:

- Eliminate exit fees for load served by existing or new CHP resources.
- Establish a procurement target for baseload CHP, as distinguished from UPF or other dispatchable resources with an identified avoided cost reflective of similar generation facilities.
- Frame a balanced and reasonable set of standard offer agreements with elective options for various types of CHP projects – large and small, firm power delivery and as available.
- Establish contracts of comparable lengths of term to the 20-30 year contracts (or rate base recovery) available to IOU resources.
- Assure that regulatory conditions applicable to CHP – like RA benefit obligations, prohibition on replacement power obligations, unit commitment obligations, and preservation of reliable interconnection facilities – remain a constant for the term of the CHP contract. Allowing changes that impose costs, risks or burdens that cannot be changed under IOU-established agreements are unfair and unbalanced for CHP resources.
- Sustain the right of thermally matched CHP resources to avoid physical curtailment or dispatch except in the event of a system emergency declared by the CAISO.

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

EPUC/CAC reply collectively in a single response to the several questions posed in this Section II.6.

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?

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

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

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

The results of the AB 1613 tariff reveal the failure of the program design to promote and secure the development of small, highly-efficient CHP. The paucity of projects relying on AB 1613 – maybe two – is telling. EPUC member Chevron Cymric relied on AB 1613 for a very small research and development project. The time, costs and challenges faced by this small demonstration project from the interconnected IOU, and through the CPUC process were deflating. Ultimately, after an extraordinarily long process, the demonstration project demonstrated a lack of feasibility. But the costs and difficulty utilizing AB 1613 as a vehicle sent the CHP developer messages not to rely on the vehicle again.

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? No, and the GHG payment is unreasonably low and non-compensatory. Absent material upgrading of the AB 1613 feed-in tariff, it will become another on the list of failed implementations of a State CHP policy goals to support the development of efficient CHP.

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 MMTCO2E annual emissions reduction by 2020)?**

The CEC's most recent CHP Market Assessment Report (CEC-200-2012-002) states that the technical potential for new CHP is well in excess of these State policy goals. Moreover, the petroleum industry alone has the potential to provide about 70% of the 6.7 MMT CO2 savings based on a calculation employing the CEC estimated new CHP technical potential and the electric system 2013 heat rate (*i.e*., a heat rate based on CAISO 2013 LMP and CPUC SRAC postings information).

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

The State can meet the incremental MW and GHG reduction goals, but only with direct and specific implementation requirements for procurement. Assuming the State's IOUs remain as CHP procurement agents (as opposed to the CAISO, the CEC or CARB) procurement will require meaningful changes to current procurement practices to encourage development of CHP resources. The following are the contemplated changes to procurement practices:

- ✓ Establish specific CHP capacity procurement targets for efficient CHP (meeting or exceeding the established double benchmark standard) for utilities beyond those delineated in the CHP Settlement. As an example, provide bottoming-cycle CHP with the highest procurement priority, and establish that such resources have zero GHG emissions for purposes of generation resource procurement.
- ✓ Establish a proactive and timely method for measuring the IOUs' progress in achieving the newly established CHP targets, including a process for rewarding success and invoking punitive measures, if necessary.
- ✓ Determine that existing, repowered or new CHP are eligible to satisfy these newly established capacity and efficiency targets and establish a separate program for

dispatchable or UPF resources distinct from baseload CHP resources in order to eliminate the demonstrated IOU procurement bias against existing baseload CHP.

- ✓ Establish reasonable pricing and contract term provisions reflective of recognized costs for combustion turbine facilities most similar to CHP resources. Contract terms should be for 20-30 years in duration to bring stability to the CHP fleet of resources. The CHP contract term should be sufficient to encourage the development and continued operation of CHP facilities.

- ✓ Require the utility procurement process to establish a priority method that includes evaluating resources on a $/CO2 basis that reflects transmission cost, firming capacity costs, supplemental energy costs and supplemental energy GHG emissions necessary for intermittent resources to be comparable to baseload CHP. Ratepayers may not be getting the best GHG savings value from resource the IOUs are selecting in the current procurement evaluation.

- ✓ Eliminate departing load charges and/or exit fee to customers employing CHP to serve load.

- ✓ Establish a commercially balanced pro forma CHP PPA with provisions that encourage CHP development and provide certainty regarding operating restrictions and obligations for the term of the PPA.

- ✓ Establish an expedited, streamlined and limited cost option for CHP interconnection procedures, including the development of a CHP specific pro forma Large and Small Generator Interconnection Agreement.

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)?

See response to Section III.2, above. In addition, experience informs that CHP procurement target requirements on the IOUs alone do not solve the problem of actually securing CHP for the state, particularly baseload CHP. Moreover, procurement targets alone have not deconstructed in a meaningful way continuing barriers to entry for CHP. Contract pricing, terms, and conditions are better suited to the establishment of an appropriate feed-in tariffs designed to secure existing and new efficient CHP. The only effective experience in California to advance CHP was the mandatory purchase obligation with a standard offer contract.

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

Please refer to the comments on dispatch and curtailment related to CHP resources in the responses to Section I.2, as well as comments on the segregation of baseload CHP and dispatchable, "flexible" host CHP and UPF facilities.

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)?**

Undeniably, the encouragement of bottoming cycle facilities as an energy efficiency program as opposed to an electric generation system would present new and positive opportunities for such facilities. There are available opportunities for manufacturing and industrial waste heat recovery though bottoming cycle CHP installation that is undeveloped. Of the other measures listed, sequestration is possible and continues to be actively evaluated. Biomethane fueled generation resources may provide additional options. However, IOU positions relative to CHP procurement, particularly on price and dispatchability grounds, chill the development of these resources.

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

Support for carbon capture and sequestration technologies would advance the combination of CCS and CHP to serve customers with material heat sinks.

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)?**

Absent a demonstrative and verifiable difference in the efficiency of the devices separately supplying the thermal energy, there is no clear rational to categorize CHP systems. If this question relates to the relative attributes of small and large CHP, there is truth to the concept that size matters. Certainly, for large commercial, manufacturing and industrial CHP, there is no basis for separate categorization. For these facilities large, demonstrated boiler efficiencies in the field are the relevant thermal generation comparisons.

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)?**

There are two preferable methods for determining the effective heat rate of the displaced grid electricity. One is a historical based method and the other is a well-vetted and auditable production simulation modeling approach.

Of these two preferred methods, the most straightforward and less controversial is the historical method. The CAISO posts the historical hourly Day-Ahead locational marginal price for multiple generation nodes. The CAISO data set also provides recorded prices at aggregation points (*e.g*., trading hubs and load aggregation points). The trading hub and load aggregation data allows the calculation of the effective heat rate at the point that the electric generation leaves the CAISO controlled grid. The heat rate at the service voltage level for a CHP facility may be calculated by adding adjustments for losses used by the IOUs (loss adjustments regularly cited in various regulatory proceedings). The historical method can be used to make an effective heat rate calculation for the level of detail the particular evaluation necessitates (*i.e*, location, time of delivery, or other consideration dependent on hourly data) with publicly available data in a transparent manner.

Alternatively, the production simulation model method typically employs a proprietary computer model that is costly to acquire and very complex to operate. While the major computational advantage of this method is the ability to simulate the impact of future projected changes in system resource configuration as well as load growth on the effective heat rate, the disadvantage is that the method requires hundreds, if not thousands of data inputs, with virtually all of these inputs subject to dispute. Moreover, underlying modeling assumptions and the manner that certain system aspects are represented in the model's list of options can significantly influence the results of such models.

EPUC/CAC appreciate the effort made by CEC staff to establish a methodology for assessing the system marginal units. There are problems with the analysis that raise concerns, particularly the use of a forecast of a continuing decline in heat rates that may not be realistic or even feasible. It is worthy of continued refinement for use with regard to new CHP resources, but the result of the Staff methodology would fail to sustain existing CHP. Existing CHP has an additional contribution that is not reflected in the marginal analysis for new projects – the fuel displacement factor is not recognized and understates the benefits of existing CHP. There may be a basis for making segregated evaluations and conclusions regarding the contributions to the grid from existing facilities that are different than those used for new CHP resources.

With respect to existing resources, and as an alternative to Staff's proposal, the historical method employing the CAISO hourly Day-Ahead Location Marginal Price data provides a method to determine the effective heat rate. One adaptation of the historical method is to evaluate the "normalcy" of the test year. If the test year appears to reflect an extreme atypical event, an average of several years may be required. The dynamics of the analytical methodology and the implications of the results of such methodology warrant careful, additional consideration.

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)?**

The efficiency of displaced thermal resources should be determine by historical operation performance data for the type and design characteristics of equipment required to supply thermal load size that is displaced by the CHP. For example, the efficiency of a residential water heater is not a valid basis for an industrial boiler producing several thousand pounds of steam per hour. Additionally, the actual operational factors such as blow down and other thermal losses attributable to real world application must be reflected in the efficiency rather than a theoretical efficiency of the equipment as purported by the manufacturer.

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?**

Historically, CHP facilities have a reporting obligation under the CPUC QF monitoring requirements, this data – upon review and assessment for real world applicability – is sufficient for thermal utilization quantification purposes. Direct metering of thermal output is not an industry standard and would be an expensive and nonproductive undertaking. CHP operators utilize prudent industrial practices relying on engineering calculation methods to determine the useful thermal energy. Metering is not an available option for most, if not all, facilities.

VI. Energy Commission Staff Proposed Methodology for Estimating Fuel Displacement

EPUC/CAC reply collectively in a single response to the several questions posed in this Section VI.

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

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

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

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.**

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

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

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

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

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

As EPUC/CAC understand the CEC's fuel displacement methodology, the underlying approach relies on a straight line or linear regression analyses to calculate a "peaking effective heat rate" and a "load following effective heat rate" for several years into the future; provided that the regression determined heat rates cannot be less that predetermined floor heat rates established by resource technology. In general, the proposed method has the advantage of being simple to replicate, transparent in its use of publicly available data and applicable to CHP resources with different operating characteristics. The approach is based on a reasonable assumption that natural-gas fired generation is the principle marginal resource now and into the future.

There appear to be a few aspects of the method that suggest that the effective heat rates and GHG reduction determinations resulting from the method will be understated. A linear regression is often driven by the beginning and end point data. This is one explanation for the method producing irrational results in the later years of the evaluation (*i.e.*, necessitating the floors). Additionally, averaging tends to understate marginal values. Thus, the historic heat rates for a given year of the regression may not be appropriate for developing displacement values. Moreover, the marginally dispatched units are impacted by suppressed load growth (or contraction) resulting from protracted abnormal economic conditions well as external factors such as atypical hydro generation. Furthermore, system condition related to force and planned outages of generation and transmission resource often result in "peaking resources being dispatched during hours of the day or months of the year that are not considered to be peak related.

As noted above, EPUC/CAC appreciate Staff's effort and analysis regarding the marginal heat rate analysis. However, the result is an export effective heat rate for a CHP facility exporting all of its generation at a 100% capacity factor of about 7,430 Btu/kWh applying the 2.5% peaking constrain to a peaking heat rate of 11,362 Btu/kWh and applying the load following heat rate of 7,330 Btu/kWh to the remaining hours. The implications of relying on such a heat rate for existing operations would be dramatic and negative. In contrast, the SP-15 effective heat rate base on 2013 CAISO hourly Day-Ahead LMP and SRAC natural gas prices is about 8,438 Btu/kWh on an annual basis. The effective heat rate in other zones will undoubtedly be different and those results warrant careful and critical evaluation as well. For the SP-15 zone, the heat rate differential is material and significant for existing CHP resources.

CONCLUSION

EPUC and CAC appreciate the opportunity to respond to CEC Staff's questions related to the CHP Workshop.

Respectfully submitted,

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