**BEFORE THE ENERGY COMMISSION
OF THE STATE OF CALIFORNIA**

In the matter of: 2012 Integrated Energy Policy Report Update (2012 IEPR Update)	Docket No. 12-IEP-1D Comments on Staff Paper October 19, 2012

COMMENTS OF THE CALIFORNIA CLEAN DG COALITION REGARDING STAFF PAPER: A NEW GENERATION OF COMBINED HEAT AND POWER: POLICY PLANNING FOR 2030

The California Clean DG Coalition ("CCDC") welcomes the opportunity to submit these comments on the staff paper titled "A New Generation of Combined Heat and Power: Policy Planning for 2030," released in September 2012 ("CHP Staff Paper"). CCDC is an ad hoc group interested in promoting the ability of distributed generation ("DG") system manufacturers, distributors, marketers and investors, and electric customers, to deploy DG. Its members represent a variety of DG technologies including combined heat and power ("CHP"), renewables, gas turbines, microturbines, reciprocating engines, and storage.[1] CCDC appreciates the consideration given by California Energy Commission ("CEC" or "Commission") to our comments and recommendations.

I. Introduction

CCDC appreciates staff's detailed presentation of the evolution of CHP in California, and its identification of the very real benefits of CHP, along with the new and ongoing barriers to realizing those benefits in California. As the CHP Staff Paper points out, while California has a long history of policy support for CHP, other of its actions serve as barriers to CHP. The CEC Staff Paper appropriately concludes that the "state's inconsistent backing of CHP … makes investors wary."[2] The result of this inconsistent treatment is that deployment of at least small

1 CCDC is currently comprised of Capstone Turbine Corporation, Caterpillar, Inc., Cummins Inc., DE Solutions, Inc., EtaGen, Inc., FlexEnergy, Inc., GE Energy, Holt of California, NRG Energy, Penn Power Systems, Peterson Power Systems, SDP Energy, Solar Turbines, Inc., and Tecogen, Inc.

2 CHP Staff Paper, p. 3.

CHP (*i.e.*, 20 MW and under) has not come anywhere close to reaching its potential and, in recent years, has stalled.

The Governor has set a goal of 6500 MW of CHP by 2030. As California implements the Renewables Portfolio Standard ("RPS") and the cap and trade program, it is the ideal time to make sure CHP has a real opportunity to benefit California and the electric system, on its own and in support of RPS and greenhouse gas ("GHG") emission reduction goals. Other current conditions also demonstrate a practical need for CHP. For example, the ongoing outage of two units at Southern California Edison Company's San Onofre Generating Station nuclear facility, and the uncertainty surrounding whether and when they might return to service, shows the impact a single large generating facility can have on supply, and the importance of having a distributed fleet of smaller clean units available to meet demand. Additionally, the phasing out of once-through cooling and the related loss of central station generation supports removal of barriers to clean CHP that can be sited at locations best suited to meet environmental goals and system load needs and help address congestion issues.

The CHP Staff Paper should serve as the impetus for making policy and regulatory changes, in the context of today's energy market, that will finally allow California to achieve its CHP goals. CCDC generally supports the list of action items identified by staff.[3] These comments focus on addressing the issues of highest priority to CCDC members. Those priorities include: (1) clarifying the role of CHP as the state increases its emphasis on renewable resources, and (2) removing barriers with an eye toward leveling the playing field for all small, clean on-site generation technologies. The barriers that most affect small, clean CHP include: (a) departing load charges; (b) standby reservation charges and high demand charges; (c) cap and trade implementation; (d) interconnection issues; (e) Self-Generation Incentive Program ("SGIP") issues; and (f) investor owned utility ("IOU") resistance to CHP.

II. Role of CHP

The key missing driver today in California is a clear vision statement for CHP. Officials at the highest levels of state and federal government have expressed strong support for CHP. As noted above, Governor Brown has set a goal of 6500 MW for CHP. President Obama recently issued an Executive Order calling for increased investment in industrial energy efficiency, including setting a "national goal of deploying 40 gigawatts of new, cost effective industrial

[3] CHP Staff Paper, pp. 5-7.

CHP in the United States by the end of 2020."[4] While these unambiguous statements of support for CHP are helpful, and consistent with longstanding California policy encouraging CHP, they will be hard to implement without clear direction as to what role CHP is to play in California's energy system.

CCDC proposes that, at a minimum, the state identify clean CHP as a resource essential to a reliable electric system and the successful integration of intermittent renewable resources, and a key contributor to achieving GHG emission reduction goals. As the CHP Staff Paper notes, CHP has many benefits. In addition to those listed by staff, as and after California transitions to a renewable-focused supply, CHP can help mitigate the cost impacts of a renewable portfolio, and help ensure a reliable supply of power, in combination with intermittent renewable resources.

In order to achieve this vision for CHP, the state should seek to remove barriers to CHP and create a level playing field for CHP and other clean on-site generation technologies.

III. Barriers

a. Need for Level Playing Field

The CHP Staff Paper does a good job of identifying very real barriers to CHP. There is one barrier alluded to in the CHP Staff Paper that warrants further explanation up front – the disparate treatment of various clean on-site generation technologies. For example, the CHP Staff Paper recognizes that Net Energy Metering ("NEM") is not available to CHP, even though it is available to other small, on-site generation, such as solar and nonrenewable fuel cells.[5] Another example is departing load charges – renewables are largely exempt, while CHP and nonrenewable fuel cells (with the exception of under 1 MW NEM-eligible fuel cells) are not.[6] Fuel cells are exempt from cap and trade regulation, but small CHP is not. Renewables and fuel cells are eligible for much higher incentives than clean CHP under SGIP. There is no procurement standard for CHP as there is for renewable resources.

This patchwork approach to treatment of and incentives for different types of clean on-site technologies creates an uneven playing field, making it very hard for CHP to compete with renewables and fuel cells, even though CHP provides many widely recognized, important

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4 Executive Order, "Accelerating Investment in Industrial Energy Efficiency," Sec. 2(a) (August 30, 2012).

5 CHP Staff Paper, pp. 5 and 46-47.

6 It appears that small nonrenewable fuel cells under 1 MW that are eligible for NEM generally do not pay departing load charges. (Pub. Util. Code § 2827.10)

benefits consistent with implementation of energy efficiency, RPS and GHG emission reduction goals. As the state considers how best to stimulate CHP development to meet MW and GHG emission reduction goals, an overarching principle should be to establish a level playing field for all clean on-site technologies.

b. Other Barriers

(1) Departing Load Charges

Departing load charges frequently are a key reason a CHP project does not go forward. They have shown up on various CHP barrier lists for years. The CHP Staff Paper appropriately continues to recognize departing load charges as a key barrier to CHP.

The public purpose program charge has grown to be the largest component of departing load charges, currently ranging from just over $0.01/kWh to close to $0.02/kWh, depending on the IOU and the rate schedule. Total departing load charges – *i.e.*, public purpose program charges combined with other departing load charges (including the nuclear decommissioning charge and the DWR Bond Charge), often exceed $0.015/kWh.

For example, analysis done for a CCDC member by a rate consultant calculated that departing load charges for a 500 kW CHP project would amount to approximately $0.015/kWh, or approximately $59,200 per year, after taking into account applicable exemptions.

Departing load charges on their own can be enough to tip the investment decision away from CHP. The addition of standby charges and the low SGIP incentive rate makes it even less likely that a customer would invest in CHP.

Imposing departing load charges on CHP is inconsistent with state policy. The public goods charge is intended to support energy efficiency and GHG emission reduction programs, including the SGIP. It simply does not make sense to penalize CHP with a fee that is intended to support CHP. To the best of CCDC's knowledge, California is one of the few states, if not the only state, that currently imposes departing load charges on customer generation. In order to relieve one of the primary barriers to CHP, decision makers should exempt CHP from departing load charges. At a minimum, CHP should not be subject to the public purpose program charges, which are intended to promote energy efficiency and GHG emission reduction measures, including CHP.

(2) Standby Charges and Demand Charges

The Legislature intended that customers installing distributed energy resources ("DER") be served – over the long-term – under rates, rules, and requirements identical to those of customers that do not use DER. Accordingly, CCDC agrees with the CHP Staff Paper that standby reservation charges and demand charges are detrimental to CHP. CCDC maintains that imposition of a standby reservation charge on DER, including CHP, is inconsistent with Legislative intent, and that demand charges for CHP should be revisited.

Analysis done for a CCDC member by a rate consultant calculated that standby reservation capacity charges for a 500 kW CHP project comprised of two 250 kW units could range from approximately $7,800 to $15,600 per year. (Reservation capacity charges may be refunded in any month where a customer incurs demand charges as a result of the non-operation of the CHP unit(s).) If an outage of one 250 kW unit occurs during peak and part-peak daytime periods, it is estimated that demand charges could add approximately $6,700 in a summer month, and approximately $2,300 in a winter month (after accounting for a reservation charge credit).[7]

Senate Bill ("SB") X1 28, enacted in 2001, added Article 3.5, "Distributed Energy Resources," to the Public Utilities Code. SB X1 28 expressed the Legislature's preference that DER be served under rates, rules, and requirements identical to those of customers that do not use DER, on an interim basis and over the long-term.

Public Utilities Code section 353.3(a) directed the California Public Utilities Commission ("CPUC") to require each electrical corporation "to ***modify its tariffs*** so that all customers installing new distributed energy resources in accordance with the criteria described in Section 353.1 are served under rates, rules, and requirements identical to those of a customer within the same rate schedule that does not use distributed energy resources … ."[8] (Emphasis added.) This

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[7] It is difficult to estimate the net impacts of reservation capacity and demand charges for a project, primarily because the nature and extent of outages are difficult to predict, but these numbers provide a reference point for indicating the impacts of such charges.

[8] Under section 353.1 of the Public Utilities Code, DER is to meet the following criteria: (1) commences initial operation between May 1, 2001 and June 1, 2003, except that gas-fired DER not operated in a CHP application must commence operation no later than September 1, 2002; (2) is located within a single facility; (3) is five MW or smaller in aggregate capacity; and (4) serves onsite loads or over-the-fence transactions allowed under Sections 216 and 218. On or before December 31, 2001, the Commission was to have adopted a real time pricing tariff for the purpose of Public Utilities Code section 353.3. (Public Utilities Code § 353.3(b).)

section was interpreted as providing DER that met the criteria of Section 353.1 with a 10-year exemption from standby reservation charges.[9]

Public Utilities Code section 353.13(a) directs the CPUC to require each electrical corporation "to establish ***new tariffs*** on or before January 1, 2003, for customers using [DER], ***including, but not limited to***, those that do not meet all of the criteria described in Section 353.1." (Emphasis added.) These new tariffs are to "ensure that customers with similar load profiles within a customer class will, to the extent practicable, be subject to the same utility rates, regardless of their use of [DER] to serve onsite loads or over-the-fence transactions allowed under Sections 216 and 218."[10]

Read together, the provisions of SB X1 28 (1) provided a 10-year waiver of standby charges for specified DER installations – the "interim" exemption, and (2) required the CPUC to require each electrical corporation to establish ***new*** rates by January 1, 2003 applicable to a broader category of DER, *i.e.*, ***new DER installed after June 1, 2003*** – the "long-term" standby charge exemption.

Additionally, Section 353.13(c) provides that in establishing the required new DER rates, the CPUC is to "consider coincident peakload, and the reliability of the onsite generation, as determined by the frequency and duration of outages, so that customers with more reliable onsite generation and those that reduce peak demand pay a lower cost-based rate."

Assembly Bill ("AB") 1613, enacted the Waste Heat and Carbon Emissions Reduction Act in 2007 (Public Utilities Code sections 2840 – 2845). Public Utilities Code section 2841(g) provides that the CPUC is to "adopt or maintain standby rates or charges for [CHP] systems that are based only upon assumptions that are supported by factual data, and shall exclude any assumptions that forced outages or other reductions in electricity generation by [CHP] systems will occur simultaneously on multiple systems, or during periods of peak electrical system demand, or both."

CCDC also notes that the 2007 Integrated Energy Policy Report ("IEPR") recommended that the CPUC and the CEC work cooperatively to eliminate standby reservation charges for DER.[11]

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9 Public Utilities Code § 353.13(a).

10 Public Utilities Code § 353.13(a).

11 2007 IEPR, Chapter 5, Recommendations, p. 212.

CCDC is not aware that the CPUC has adopted the new DER rates called for in Section 353.13(a), or addressed the provisions of AB 1613 relating to standby charges for CHP. CCDC encourages the expeditious development of appropriate DER tariffs that provide the long-term relief from standby reservation charges intended by the Legislature and that adopt reasonable demand charges, consistent with Public Utilities Code sections 353.13 and 2841(g). (Such DER tariffs could also address appropriate exemptions from departing load charges.) Regulatory authorities should also consider making optional rate schedules without demand charges available to CHP, similar to the rate schedules currently available for qualifying non-NEM renewable customers.

(3) Cap and Trade

As the CHP Staff Paper states, regulatory uncertainty associated with cap and trade as it may apply to CHP is a significant barrier. CCDC appreciates the August 24, 2012 letter from California Air Resources Board ("CARB") Chair Mary Nichols stating CARB's intent to address cap and trade issues for CHP, and the September 20, 2012 CARB Resolution 12-33 memorializing that intent. Specifically, CARB has stated its intent to exempt the steam or waste heat emissions for all CHP facilities that would not otherwise be covered by cap and trade "but for" their investment in CHP, based on a benchmark, until 2015 when both electricity and natural gas will be covered by the program. CCDC members plan to participate in the 2013 CARB rulemaking proceeding, where the details of this important transition relief program will be defined.

(4) Interconnection

The CHP Staff Paper correctly identifies the currently cumbersome, costly and lengthy interconnection process as a barrier to CHP. CCDC members did not have the resources to participate in Phase 1 of the recent interconnection settlement proceedings at the CPUC. CCDC understands that Phase 2 is just getting underway, and that there may be an opportunity to address issues important to CHP in that Phase. In addition to interconnection process and schedule certainty, another priority for CHP is addressing meter requirements and costs, in the context of interconnection, and for purposes of other incentive programs, like SGIP.

(5) SGIP

CHP was recently reinstated as a technology eligible for SGIP, after several years of ineligibility.[12] While that is generally good news, the level of SGIP incentives available to CHP, combined with the budget allocated to nonrenewable technologies and the ability of the Program Administrators to move monies from the nonrenewable budget to the renewable budget at their discretion, is another example of "inconsistent backing" of CHP. Under the revised SGIP, nonrenewable CHP is awarded 25% of the SGIP budget and renewable and emerging technologies are awarded 75% of the budget. At $0.50 per watt, CHP is eligible for the lowest SGIP incentive rate. Renewable and emerging technologies, including fuel cells are eligible for incentives ranging from $1.25 per watt (renewable) to $2.25 per watt (fuel cells). The fuel cell incentive may increase to $4.25 per watt with the biogas adder.

At these incentive levels, CHP offers ratepayers a superior value relative to other SGIP-eligible technologies, due to CHP's strong contribution to GHG emission reduction goals and other benefits. For example, traditional CHP technologies afford the State with appreciably more benefits for the SGIP budget than natural gas emerging technologies. Traditional CHP costs the State (*i.e.*, SGIP) 75% less than natural gas emerging technologies per kW, and provide greater GHG reductions per kW for efficiently designed systems.

Even though CHP starts out with a small share of the program budget and the lowest incentive levels, despite its comparative benefits to SGIP goals, Program Administrators are able to move funds from the nonrenewable budget to the renewable and emerging technologies budget at their discretion. An advice letter is required to move funds in the other direction. That risk of fund depletion poses a very real risk for investors. PG&E recently moved nearly half of its non-renewable budget to its renewable and emerging technologies budget.

Since becoming eligible for SGIP again, CHP developers have had to begin marketing in California, essentially from a standstill, and that process takes time.[13] In contrast to renewable developers who have been continuously eligible for SGIP, CHP developers did not have applications in the queue and/or ready to go when Program Administrators resumed accepting applications in 2012. Without certainty that even the low levels of incentives for CHP will be available for any period of time, the marketing process is that much more difficult.

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[12] CPUC Decision No. 11-09-015.

[13] It generally takes between nine and 18 months to complete the sales cycle for a small CHP project.

Various options could be considered for providing greater SGIP certainty to CHP. The Program Administrators could be directed not to shift funds from the non-renewable budget to the renewable and emerging technologies budget over the next six months, the budget for CHP could be increased to 40%, or the per-watt incentive level could be increased.

(6) Utility Concerns

CCDC is concerned that the discussion of "Utility Concerns" in the CHP Staff Paper understates the effect of investor owned utility ("IOU") bias against CHP over the years.[14] CCDC agrees with the IOUs that a robust CHP program should take into account CHP's role in California's energy landscape, the potential for CHP to provide cost-effective GHG reductions, and the potential for CHP to provide operating flexibility to support intermittent generators.[15] Those points relate to the current focus on renewables and GHG emission reductions and the vision for CHP proposed above. The CHP Staff Paper does not mention historic IOU resistance to CHP. That resistance has taken the form of IOU-proposed or supported departing load charges, onerous standby charges, and unduly burdensome and costly AB 1613 contract requirements, among other things. Proactive electric and gas IOU support for CHP is essential to achieving state CHP goals. Support activities could include:

- Incentive-based ratemaking similar to that implemented for energy efficiency
- Outreach
- Feasibility study support
- Project financing (utility ownership, lease structure); on-bill payments.

CCDC suggests that a CPUC- or CEC-facilitated negotiation between the CHP community and the IOUs may be a reasonable option for resolving some of the CHP barrier issues.

IV. Conclusion

The CEC Staff Paper provides an excellent summary of how CHP in California has evolved, and of barriers to its further deployment going forward. CCDC strongly recommends that the CEC, the CPUC and CARB work cooperatively with stakeholders to develop a clear path forward for CHP that removes barriers and allows CHP to compete on a level playing field with

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14 CHP Staff Paper, pp. 47-48.

15 *Id*. at 47.

other small distributed technologies. CCDC respectfully submits that any plan for the future should take into account the suggestions made in these comments.

CCDC reiterates its appreciation for the CEC's consideration of these comments.

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