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

In the matter of: 2014 Combined Heat and Power Staff Workshop	Docket No. 14-CHP-1 Comments Following Workshop Regarding Combined Heat and Power August 18, 2014

COMMENTS OF THE CALIFORNIA CLEAN DG COALITION FOLLOWING THE JULY 14, 2014 CALIFORNIA ENERGY COMMISSION COMBINED HEAT AND POWER WORKSHOP

The California Clean DG Coalition ("CCDC") appreciates the opportunity to submit these Comments Following the July 14, 2014 California Energy Commission ("CEC") Combined Heat and Power ("CHP") Staff Workshop. 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 CEC staff and the Commission to its comments and recommendations.

Introduction

CCDC appreciates the CEC staff's continued evaluation of "the benefits, challenges, and practical solutions to incentivizing development of clean and efficient [CHP] resources in California."[2] Staff correctly observes that even with programs purporting to encourage CHP, its "development in California has been slow."[3] CCDC has often advocated that, as part of the effort to address longstanding barriers to CHP, the benefits of DG must be valued and taken into account in order to develop a regulatory framework that ultimately achieves the State's goals for CHP. This proceeding provides a much needed forum for further discussion of barriers and

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

2 Notice of Staff Workshop on CHP, p. 1.

3 *Id*. at p. 2.

developing a methodology to measure and properly value the benefits of CHP. Following are CCDC's responses to the Questions for Stakeholders. CCDC primarily focuses on "small" CHP, *i.e.*, CHP systems that are 20 megawatts ("MW") or under.

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?*

In 1998, the California Public Utilities Commission ("CPUC") issued an Order Instituting Rulemaking ("OIR") (R.98-12-015) to consider "the impact of distributed generation [generally, not just CHP] on California's electricity distribution system, and to consider whether reforms are needed with respect to the regulatory framework which governs electricity distribution service."[4] In a decision in that OIR, the CPUC observed that the benefits of DG:

> …could include …wider customer choice; the [DG] facilities can provide backup service, or provide all of the electric needs of the end-user; the cost of installing and operating the [DG] may be lower than the current cost for electricity; the facilities can improve the end-user's power quality and reliability; [DG] facilities may improve system reliability and may reduce T&D line losses; the installation of such facilities may result in the avoidance or deferral of distribution system investments; the siting of [DG] facilities may provide relief to constrained distribution systems; and there may be environmental benefits depending on the type of technology employed and the type of fuel that is used.[5]

Stakeholders have been debating the nature and extent of these (and other) benefits in various proceedings and forums since at least 1998. CCDC continues to maintain that existing small CHP systems provide substantial benefits to electric utilities and the Independent System Operator ("ISO"), including and in addition to those identified in 1999. By providing some or all of the electric service needs of the end-user, existing small CHP reduces the electricity procurement obligations of an electric utility and reduces demand on the ISO grid. Small CHP, which generally functions as an intermediate or baseload resource, improves grid reliability and reduces transmission and distribution line losses. In many cases, small CHP may avoid or defer distribution system investments by electric utilities, and it may reduce congestion on certain distribution systems. Small CHP also reduces emissions of greenhouse gases ("GHG"). And, today, small CHP is a highly efficient, reliable resource that can help stabilize the grid as more and more variable renewable resources come on line to meet State requirements.

[4] D.99-10-065, p. 2.
[5] *Id*. at p. 17.

While there presently are very few exporting small CHP systems, CCDC believes that such systems enhance or have the potential to enhance the benefits described above because an end-user is able to size a CHP system to meet onsite thermal load, thereby increasing the quantity of benefits provided.[6] Notably, deliveries from such systems must be scheduled with the ISO, and State law provides that they shall count toward the purchasing electric utility's resource adequacy requirements.[7]

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

Grid operators want new CHP resources (within the group, but not necessarily individually) to possess the following attributes: to be reliable, reduce line losses, avoid or defer grid upgrades, and/or relieve congestion. In general, new CHP can provide these characteristics under current grid circumstances. However, ongoing barriers prevent meaningful deployment of new small CHP.

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?*

CHP end users presently are required to provide substantial operational information as part of the process of applying for an interconnection agreement, Self-Generation Incentive Program ("SGIP") incentives, and/or an AB 1613 Power Purchase Agreement,[8] under AB 32, and for use in monitoring system performance under certain programs.[9] They are also required to provide substantial deposits in connection with those programs.[10] Over the years, various reports and CHP program evaluations have provided information regarding market assessments,

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6 Currently, small CHP may only export under the AB 1613 program. (PU Code § 2841.)

7 *See, e.g.*, PG&E Form 79-1120, Standard Contract for Eligible CHP Facilities (up to 20 MW), Section 2.01(b)(iii); PG&E Form 79-1121, Standard Contract for Eligible CHP Facilities (5 MW and under), Section 1.08; and PU Code § 2841(f).

8 AB 1613 added the Waste Heat and Carbon Emissions Reduction Act to the Public Utilities Code (PU Code §§ 2840 – 2845).

9 *See, e.g.*, the IOUs' Rule 21 governing interconnections; the 2014 SGIP Handbook and related forms; the CEC Guidelines for Certification of Combined Heat and Power Systems Pursuant to the Waste Heat and Carbon Emissions Reduction Act, Public Utilities Code Section 2840 *et. seq.*; and the AB 1613 PPAs.

10 *Id*.

pay-back periods, standby charges, and departing load charges ("DLCs").[11] Accordingly, it is not clear what additional operational or economic data from CHP end users would allow for a more complete and accurate analysis of the benefits and costs of CHP.

CCDC believes that additional economic data from the electric utilities would be useful. For example, what is the amount of the costs that a utility avoids when a customer installs CHP? How do those avoided costs compare to the amount of DLCs a customer pays? Historically, does the distribution service requirement that is reduced or avoided when a customer installs CHP result in distribution facilities sitting idle, or is a utility able to use those facilities to supply other distribution demand and avoid or defer investment in distribution facilities? Which locations on the utility distribution system are suited to CHP and which are not?

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

CCDC recommends that a comprehensive list of currently available information be developed to avoid duplication of effort and delay in this proceeding. Similarly, a comprehensive list of remaining data needs should also be developed. With respect to some of this information, a process for maintaining confidentiality may need to be developed.

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

ICF and Itron have in the past analyzed CHP costs, including comparing CHP to other resources. It would be useful to update those studies. CCDC is interested in working with stakeholders to develop a framework for updating those studies.

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

CHP provides other categories of benefits (in addition to those discussed above), and stymied CHP development results in other categories of costs.

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[11] Examples of such reports and evaluations include the Consultant Report prepared for the CEC, "Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment," ICF International (February 2012) CEC-200-2012-002 (available at: http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf); and Final Consultant Report Prepared for the CEC, "Combined Heat and Power Market Assessment," ICF International (April 2010) CEC-500-2009-094-F (available at: http://www.energy.ca.gov/2009publications/CEC-500-2009-094/CEC-500-2009-094-F.PDF).

Other Benefits:

GHG Emission Reductions

As the California Air Resources Board ("CARB") recognized in the Climate Change Scoping Plan, CHP has the potential to reduce GHG emissions and it accordingly set a target of an additional 4,000 MW of installed efficient CHP capacity by 2020. PG&E and ICF have each prepared papers analyzing CHP and GHG emission reductions. It is time for the CEC and CARB to work together to develop a methodology that ensures that the GHG emission reductions attributable to CHP are properly valued. As part of this effort the CEC and CARB should also consider the CEC staff paper regarding a proposed method for estimating fuel displacement for California electricity reductions when it is issued.[12]

Renewables Integration

California law requires that at least 25% of its electric supply is generated by renewable resources by 2016, and 33% by 2020. GHG emissions are to be reduced to 1990 levels by 2020, further demonstrating the importance of renewable resources. Because renewable energy is dependent on natural conditions, its availability on and even within any day varies. Natural gas resources are necessary to stabilize the grid in the face of this variability. Intermediate (4500 – 6500 hours) and baseload CHP (over 6500 hours) is well suited to help stabilize the grid and integrate renewable resources.

Efficient Use of Energy

As described in the Final CEC Staff Paper, "*A New Generation of Combined Heat and Power: Policy Planning for 2030*" ("CEC CHP Staff Paper"), CHP generates onsite electricity and useful thermal energy in an integrated system.[13] CHP systems use less fuel than would be required to separately generate electricity and thermal energy. This results in more efficient fuel use and reduced energy costs. Reduced energy costs may be calculated using usage data, current tariffs, and market prices. Other benefits from energy efficiency may include lower GHG

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[12] Draft CEC Staff Paper, "*Estimating Fuel Displacement for California Electricity Reductions: Summary of Staff's Proposed Method*," prepared for discussion at the July 14, 2014 Staff Workshop.

[13] Final CEC Staff Paper, "*A New Generation of Combined Heat and Power: Policy Planning for 2030*," (September 2012), CEC-200-2012-005, p. 1 (available at: http://www.energy.ca.gov/2012publications/CEC-200-2012-005/CEC-200-2012-005.pdf).

emissions, improved public health, lower energy prices, job creation, increased income, improved national security, and reduced construction expenses for utilities.[14]

Grid Security and Stability

Because small CHP is disbursed throughout the grid, it enhances grid security and reliability, alone or when considered in combination with small renewable DG. There will be less impact to customers if one small CHP system goes down, compared to a large central station power plant. The removal from service of Southern California Edison's San Onofre Generating Station nuclear facility 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. Similarly, the phasing out of once-through cooling and the related loss of central station demonstrates the need for disbursed reliable generation.

Reliability of CHP as a class is on the order of 95% available and enhances grid resiliency at the generation, transmission, and distribution levels.[15]

Other Costs:

Disparate Treatment of Clean, Onsite Technologies

Currently, the incentive playing field for small onsite generation is not level. CHP is not eligible for net energy metering, even though other small, onsite generation, such as solar and nonrenewable fuel cells, are eligible. Similarly, small renewable generation and nonrenewable fuel cells under 1 MW are exempt from DLCs, but CHP is not. Fuel cells are exempt from cap-and-trade regulation, but CHP is not. Renewables and fuel cells are eligible for much higher incentives than clean CHP under SGIP. It appears that the benefits of CHP are not being accounted for, or are being minimized, when incentive programs are established. The incentive playing field must be based on consideration of the benefits and costs of all small DG technologies and incentives adjusted accordingly to ensure it is level.

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[14] State and Local Energy Efficiency Action Network, "*Energy Efficiency Program Impact Evaluation Guide*," (December 2012), DOE/EE-0829.

[15] In addition, the United States Environmental Protection Agency ("USEPA") has suggested on its web site a method of calculating reliability benefits from CHP based on installing CHP instead of a backup or emergency diesel generator. (USEPA, "*Calculating Reliability Benefits*," available at: http://www.epa.gov/benefits.html.) The cost of service disruption depends on the function of the system impacted and can vary widely.

Customer Preference

Customers desire cost effective, reliable electric service. Customers also increasingly seek to minimize their impact on the environment, including by modifying operations to reduce GHG emissions. To meet these goals, it makes sense in certain customer circumstances, for a customer to install CHP. Unfortunately, the impact of DLCs (alone, or in combination with other barriers) frequently tips the scale in favor of a decision not to install CHP. It is poor policy for the State to act in a manner that tilts the technology playing field, thereby biasing customer selection. As the economy in California continues to recover and customers increasingly are able to invest in the economy, it is important to account for customer preference, perhaps by calculating the value of lost opportunity in terms of foregone investment and lost jobs.

Inertia

The pattern over the last 15 or so years reflects significant inertia. Small CHP representatives seek to remove barriers to and increase deployment of CHP; the electric utilities seek to prevent loss of load. The result is that while stakeholders are having largely the same debates today over cost and benefit issues as they were having 15 years ago when the CPUC opened its DG rulemaking, CHP is not being deployed as desired by the State of California. This is not without cost to California. Opportunities to reduce GHG emissions are being missed, customers are not able to install CHP when they have suitable thermal load, and grid benefits are being lost. These costs may be defined to include lost investment, lost jobs, and otherwise avoidable or deferrable transmission and distribution costs, efficiency costs, GHG emission costs, and grid reliability costs.

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)?*

DLCs, as well as standby and demand charges, are often the economic factors that result in a “do not invest” in CHP decision. DLCs are discussed further in response to Question II.2., below.

Other economic factors that contribute to the decision to invest in CHP include electric rates and reliability, payback period, cap-and-trade compliance costs, interconnection process burdens and costs, an uneven incentive playing field, and investor owned utility resistance to CHP.

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

DLCs often make a new CHP project uneconomic, such that a customer or developer does not proceed with a project. Customers considering CHP do not understand the rationale for DLCs, especially when they are trying to act within long articulated State policy purporting to support CHP, and they know they are reducing procurement and likely other costs for an electric utility.

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

A recent report by Aspen Environmental Group, "*Independent Review of 'Onsite Generation in CA: Potential Ratepayer Savings and Key Barriers'*" ("Aspen Report"), demonstrates that "from 2010 through 2013, DG would have provided enough economic benefit to other ratepayers to more than offset the value of "Departing Load Charges" (DLCs)."[16] In other words, so long as DLCs continue, other ratepayers will not realize in rates the benefits of CHP. It is vital that the value of the benefits of CHP be considered in determining the net impacts of CHP.

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

As noted above, many analyses and studies have been prepared over the years to quantify CHP impacts and the results of various CHP and/or DG incentive programs. Most recently, the Aspen Report reviewed a study showing that DLCs not only harm DG (including CHP) developers, but they also harm other ratepayers because they prevent DG from being installed and the resulting downward pressure DG exerts on rates. As discussed above, CCDC recommends that the CEC develop a list of existing relevant studies, to avoid duplication, ensure the most efficient use of resources, and break the pattern of inertia.

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[16] "*Independent Review of 'Onsite Generation in CA: Potential Ratepayer Savings and Key Barriers'*," Aspen Environmental Group (June 11, 2014), p. 3, available at: http://chpassociation.org/wp-content/uploads/2014/06/Indepenedent-Review-of-Onsite-Generation-in-CA-Potential-Ratepayer-Savings-and-Key-Barriers-Final.pdf, and included as an attachment hereto.

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 fee (*i.e.*, DLC) allocations that continue indefinitely, without transition or restriction, are not appropriate for CHP facilities (or possibly for any departing customer). CCDC submits that California should rethink its approach to exit fees. The law allows, and in some cases encourages, customers to install CHP. Fundamentally, it is inconsistent for the State to, on the one hand, set policies and programs purporting to encourage CHP, while, on the other hand, impose draconian exit fees on customers who install CHP. Going forward, the CEC and the CPUC should acknowledge that under the law, customers have limited alternatives to investor owned electric utility service, and that pursuit of such alternatives does not automatically harm, and in fact may benefit, remaining ratepayers.

As an alternative to exit fees, stakeholders should focus on a solution that encourages electric utilities to support CHP.

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 examples of how these challenges were, or were not, overcome.*

As noted, the biggest challenge to new CHP is DLCs. Incentive levels are another significant issue. Not only is the playing field for small onsite generation not level (as described above in response to Question I.5.), but even CHP-focused programs, like AB 1613 are not implemented in a manner that generates participation.

CCDC member NRG has encountered two situations where the thermal load would have been a perfect match for clean efficient CHP. NRG viewed the projects as ideal opportunities to also reduce GHG emissions. Thus, even though the projects seemed excellent fits for the intended uses and would have helped meet State GHG emission reduction goals, the AB 1613 feed-in tariff and associated charge structures , even with the location bonus, led to projected returns that were not able to meet internal hurdle rates for deployment of capital. The only other procurement options for CHP are the utility RFOs under the Qualifying Facility CHP settlement, but new CHP is not able to compete with the older systems being secured under those RFOs.

Interconnection delays and costs add uncertainty (see response to Question II.6.d. below).

And, importantly, cap and trade creates an uncapped liability that has derailed many CHP projects. CHP displaces less efficient wholesale fossil generation sources from the California grid. CARB currently uses an emissions benchmark of 0.431 MTCO2e/MWh which corresponds

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to a 42% efficient natural gas generating plant. The GHG emissions reductions from efficient CHP are considerable when compared to this baseline. However, because the grid is not comprised of 100% natural gas power, the economic linkage between the carbon cost adder in natural gas and the carbon cost adder in electricity is distorted. Eligible renewables, large hydro, and nuclear are included in the electricity carbon adder, which means that the adder is about one half what it would be if it were all natural gas. This results in a negative economic signal instead of a positive economic signal for CHP.

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

<u>Eliminate Departing Load Charges</u>

The benefits of CHP to customers and electric utilities should be confirmed and valued, in support of ending DLCs for CHP. The CPUC could also consider developing a tariff for DER, as called for in Public Utilities ("PU") Code section 353.13. Such a tariff could be designed to better balance utility interests, CHP developer interests and thermal host needs, and, to a degree, State GHG reduction targets.

<u>DER Tariff</u>

Senate Bill (SB) X1 28, enacted in 2001, added Article 3.5, "Distributed Energy Resources" ("DER") to the PU 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.

PU Code section 353.3(a) directed the 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 … ."[17] (Emphasis added.)

[17] Under section 353.1 of the PU 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 CPUC was to have adopted a real time pricing tariff for the purpose of PU Code section 353.3. (PU Code § 353.3(b).) CCDC is not aware that the CPUC adopted such a tariff.

PU Code section 353.13(a) directed 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." (PU Code § 353.13(a).) In establishing these tariffs, the CPUC is to consider coincident peakload, and the reliability of onsite generation, based on 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. (PU Code § 353.13(c).)

As described in the April 2, 2001 Assembly Committee on Energy and Cost Availability Committee Bill Analysis, 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 ***new [DER] installed after June 1, 2003***" [the "long-term" exemption]. To the extent practicable, these rates are to be the same as for other, non-[DER] customers with similar load profiles." (Bill Analysis, pp. 3-4.)

In April 2003, the CPUC issued D.03-04-060 as a "temporary step to implement § 353.13 … because the [CPUC] has not yet completed the process of setting new rates for distributed generation customers as required by § 353.13(a)(1)." The CPUC determined that the temporary (*i.e.*, "interim") tariffs expired in 2011.

Thus, while the CPUC may have previously authorized tariff ***modifications*** to implement the 10-year standby charge waiver for CHP DER installed prior to June 1, 2003, it has not authorized the ***new*** DER tariffs required by PU Code § 353.13(a) for systems installed after June 1, 2003. Therefore, under the applicable statutory language, as interpreted by the CPUC in D.05-11-005, standby charge exemptions remain in effect.

The CPUC could undertake now to develop the required DER tariff. Any such tariffs should implement the Legislature's intent that the standby reservation charge should not apply to eligible DER. They could also clarify that DLCs do not apply to eligible DER. And, importantly, they could include measures to ensure customers are compensated for the value they provide, and the utilities receive benefits from the installation of DER. These values and benefits should account for resource adequacy, GHG emission reduction and other environmental attributes, transmission and distribution benefits, and efficiency attributes. Additionally, the tariff could provide a means for a utility to acquire an ownership in a DER facility.

GHG

With respect to GHG, the GHG reduction accounting issue described in the CEC CHP Staff Paper remains a problem.[18] Currently, CHP electricity that is consumed onsite is *not* taken into account when calculating the total energy generated for purposes of the renewable portfolio standard ("RPS"). This is different than the treatment of exported electricity, which becomes part of the utility's RPS calculation. As the CEC CHP Staff Paper recommends, all electricity generated by CHP, whether consumed onsite or exported, should be included in the RPS calculation, and compared to the utility's marginal generator.[19] Without such a change, CHP will have to compete with grid electricity that increasingly is comprised of renewable resources, which will be impossible for CHP to beat. While CHP may be leaner than a utility's marginal generator, it may not be cleaner than the grid's overall resource mix. The Legislature or the CPUC should clarify that all electricity generated by CHP, whether consumed onsite or exported, must be included in the RPS calculation.

In response to Question II.4. above, CCDC discusses some of the issues affecting CHP under cap and trade.

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?*

The AB 1613 tariff does not provide enough financial support to drive investment in CHP. According to the CEC web site, through June 2013, only four projects have been certified as eligible for AB 1613, and only one of those has signed a power purchase agreement ("PPA").[20] The CPUC approved the AB 1613 program nearly four years ago.[21] The lack of participation shows that the program in its current form is not working. One issue is financial

18 CEC CHP Staff Paper, p. 51.
19 *Id.*
20 *See* CEC website: http://www.energy.ca.gov/renewables/tracking_progress/documents/combined_heat_and_power.pdf.
21 D.10-12-055.

support. The price paid for energy delivered under an AB 1613 contract is substantially less than the price paid under net energy metering. AB 1613 customers do not receive payment for the environmental benefits they provide through reduced GHG emissions. And, even in cases where it applies, the location adder does not necessarily make AB 1613 economic.

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

AB 1613 allows for the export of electricity by eligible onsite CHP. This appeared to provide a much needed path for customers to size a CHP system to meet its thermal load. Thus, while availability of the AB 1613 feed-in tariff should positively affect a decision to invest in a CHP project, the regulatory program implementing AB 1613 is cumbersome, costly, and time consuming, and generally is not economic for customers.

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

There currently are three possible AB 1613 power PPAs, one for systems between 5 and 20 MW, one for systems 5 MW and under, and one for very small CHP below 500 kW. The idea behind this framework was to provide some procedural and cost relief for smaller systems. Developing this framework took several years, and many issues were hotly contested. Given the dire participation results across all contract types since the program was implemented, it is clear that there are significant issues with the current framework. As described above, the price paid for energy is a significant issue. Additionally, DLCs apply to AB 1613 customers. Under the 5 – 20 MW PPA, development security and performance assurance requirements are unduly burdensome. Scheduling coordinator fees under the 5 MW-and-under PPA create a cost burden and should be reevaluated to make sure they accurately reflect a utility's costs. The interconnection process is complicated and can take much longer and cost much more than a developer or customer anticipates. Achieving full capacity deliverability status is a particularly challenging part of the interconnection process for AB 1613 customers above 5 MW. Alone and cumulatively, these are significant deficiencies in the current implementation of AB 1613.

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

As soon as a utility receives an inquiry from a potential AB 1613 customer, the utility should let the customer know that the customer must also undertake an interconnection process. CCDC understands that utility procurement and transmission departments are precluded from working together, but procurement departments should have a way of putting potential AB 1613 customers in touch with appropriate personnel in transmission departments as soon as possible. The utility should be clear about interconnection options, applicable tariffs, and processes and timelines. In that regard, the utility should be clear about the difference between "energy only" and "full capacity deliverability status". For example, energy only payments under an AB 1613 contract are much less than payments for energy from a resource that has obtained full capacity deliverability status. Additionally, it can take two or more years to obtain full capacity deliverability status, at substantial cost. Customers generally are not in the energy industry and have no idea about the intricacies of the interconnection process and its relationship to pricing under the AB 1613 PPA. They should be given as much information as possible about these issues as soon as possible. Since the utility likely is the first point of contact for a potential AB 1613 customer, the utility should be responsible for at least providing the customer with the information it needs to begin the interconnection process.

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)?*

CCDC believes there is more than enough economic and technical potential for CHP resources in California to achieve the numerous CHP deployment goals. These goals include the 6,500 MW of additional CHP capacity by 2030 goal set by the Governor's Clean Energy Jobs Plan, and the 4,000 MW of new CHP generation by 2020 set in the ARB's Scoping Plan for AB 32. The CPUC also approved a settlement requiring that California's three largest investor owned electric utilities to procure a minimum of 3,000 MW of CHP capacity until 2015.

ICF's CHP database currently lists 8,757 MW of existing CHP.[22] In 2012, ICF's "*Combined Heat and Power Policy Analysis and 2011-2030 Market Assessment*" analyzed the industrial, commercial, institutional and multifamily residential markets to quantify the technical potential for CHP in California.[23] The CHP sizing was based on the site thermal load and ICF assumed 8,519 MW of existing CHP. The result tallied 14,293 MW of remaining *technical*

[22] ICF International, "*CHP Database,*" available at: http://www.eea-inc.com/chpdata/States/CA.html.

[23] ICF International, "*Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment,*" (February 2012); available at: http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf.

potential in existing facilities and an additional 1,671 MW from expected business growth through 2030. About 5 GW of this capacity would need to be exported to the grid versus used on site (due to higher onsite thermal loads versus onsite electric power loads).

In 2013, the American Gas Association asked ICF to calculate the existing *economic* potential for CHP systems below 100 MW in the U.S. industrial, commercial, institutional, and multi-family residential market sectors. The resulting report, "*The Opportunity for CHP in the United States*," calculated the potential for new CHP in California with a less than 10-year payback to be 9,018 MW in its base case scenario.[24] This did not include estimates for future CHP based on business growth. This paper also modeled scenarios to evaluate the effect of (1) changes in CHP equipment capital cost, and (2) changes in electricity prices, on the paybacks and resulting calculation of economic potential. Under each of these scenarios, the potential for CHP in California with a less than 10-year payback increased to 11,826 MW. CCDC is not aware of other CHP potential studies done for the California market, but these two studies identify more than enough CHP potential to meet State CHP deployment goals.

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

CCDC believes there are several actions the State could take to help meet its CHP deployment goals. As explained in prior CCDC comments on the CEC CHP Staff Paper, CCDC believes the State needs to have a consistent policy of backing CHP. Existing barriers that most affect small, clean CHP include: (a) DLCs; (b) standby reservation charges and high demand charges; (c) cap and trade implementation; (d) interconnection issues; (e) SGIP issues; and (f) investor owned utility resistance to CHP.

To address the economic barrier of DLCs, there is a bill in the legislature authored by Assembly Member Kevin Mullin, AB 365, which recognizes that there is a quantifiable benefit to all ratepayers from investment in onsite generation, including CHP, by a utility customer. CCDC believes that finding supports providing relief from DLCs assessed against generation produced and consumed onsite for that customer under current CPUC decisions. As noted above, the Aspen Report confirmed that the benefit to ratepayers in the form of a reduction in market prices and avoided transmission and distribution charges outweighs the cost of this exemption from DLCs, which is already provided to other distributed generation technologies

[24] ICF International, "*The Opportunity for CHP in the United States*" (May 2013); available at: http://www.aga.org/Kc/analyses-and-statistics/studies/efficiency_and_environment/Pages/TheOpportunityforCHPintheUnitedStates.aspx.

eligible under California's net energy metering program. AB 365 properly recognizes the benefits to provide relief from DLCs for qualifying new DG. The Legislature should take the next step and provide that customers who install such DG should not be responsible for DLCs for generation they produce and consume onsite.

Facilities with CHP systems usually require supplemental and/or standby/back-up service from the utility to provide power needs over and above the output of the CHP system and during periods when the system is down due to routine maintenance or unplanned outages. Electric utilities often assess specific standby charges to cover the additional costs the utilities incur as they continue to provide generating, transmission, or distribution capacity (depending on the structure of the utility) to supply backup power when requested (sometimes on short notice). The level of these charges is often a point of contention between the utility and the consumer, and can, without proper oversight, create unintended and important barriers to CHP. The Legislature should also allow customers that install new qualifying CHP onsite to provide an estimate of their standby charges instead of allowing the utility to set these charges.

The State recently extended the Self Generation Incentive Program for an additional five years. This program does support CHP deployment, however the administrative process, the incentive structure, and aspects of the metering requirement slows project development. SGIP program changes are discussed further in response to Question III.4 below.

To address the availability of financing for potential CHP adopters, the State should establish an on-bill financing mechanism through utility or property tax bills to help end users find low cost financing for capital intensive CHP projects.

Finally, the State should eliminate or reduce other barriers discussed herein, including AB 1613 and cap-and-trade implementation for CHP, and interconnection issues.

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)?*

CHP procurement targets are helpful to demonstrate State support for CHP adoption. Voluntary targets are high-level indicators of State support, but unless there is a mandatory requirement, there is no means of enforcement. California is already short of its previously stated CHP procurement goals. Subdividing these targets by technology types may make it harder to meet these goals. However, if the State decided to subdivide the general CHP procurement target, CCDC believes this should only be done using a performance- or outcome-based approach and should take into account the performance specifications of commercially available technology.

For instance, the State could encourage high levels of CHP system resiliency by setting a procurement target for resilient CHP and identifying facilities that would be good targets for this type of CHP, such as hospitals, data centers, wastewater treatment facilities, emergency call centers, disaster relief shelters, etc. If the State is supporting CHP deployment to achieve specific goals and wanted to better target deployment towards meeting those goals, it would make more sense to set performance- or outcome-based targets than selecting specific technologies and setting procurement targets without reference to the end goal.

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

As noted above in response to QI.5, the incentive playing field for small onsite generation is not level. Incentive levels should be performance-based and consider benefits and costs of small DG technologies. For the SGIP program, non-renewable CHP has been in and out of the program's eligibility guidelines. It currently is in, but at a much lower level than other technologies, even though on a per-dollar-invested basis, it provides relatively higher benefits. SGIP is also burden with monitoring and verification requirements that further detract from the bottom line incentive. Additionally, the budget for CHP is subject to downward adjustment (without notice) by Program Administrators, while budget adjustments for other categories must go through the Advice Letter process. Businesses need continuity and certainty in policy for business planning, especially for the typical CHP sales and project cycle, which can take more than a year. The SGIP should be revised to provide that continuity and certainty. The allocation of the budget among eligible technologies should take into account the benefits each technology provides, and at what cost. Advice Letters should be required to move funds from the non-renewable category to the renewable category, as they are to move funds in the other direction.

The SGIP application process is currently the responsibility of the CHP customer or site owner and requires a lot of paperwork and can seem repetitive. The program is also primarily administrated by the electric utilities as opposed to an independent entity. Utilities often view CHP as a competitor, so their incentive to market the program and push for program success is limited. Also, the people within the SGIP administrator entities are typically not specialists on the various types of generating systems so they may ask customers for data that doesn't apply (*e.g*. requesting an updated air permit when a technology is already CARB-certified and thus exempt from additional air permitting requirements). Utility bills differ by utility and sometimes by season, and they can be very difficult to decipher to get the information requested. Metering costs for smaller DG systems can be as much or more than the incentive amount, limiting any benefit to the project. Other state programs have alternative approaches to metering that allow systems to capture performance data at a lower cost to the customer. The State should review the New York State Energy Research and Development Authority's ("NYSERDA") CHP Acceleration Program for an example of a less burdensome, highly effective CHP deployment incentive program.[25]

Other measures, such as a DER tariff and on bill financing would also help stimulate market participation.

IV. Technology Innovation to Overcome CHP Barriers.

No comment.

V. Electrical Generation Unit and Reference Boiler Efficiency.

1. *How should CHP systems be categorized, if at all, for purpose of comparing them to separate heat and power?*

CHP systems do not need to be categorized for purposes of assessing GHG performance relative to avoided grid and avoided site boiler emissions. The GHG footprint of a particular system varies with technology type, technology size and site thermal requirements.

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)?*

The avoided or marginal wholesale generation resource should be used. A simple method is preferred if workable. An average marginal heat rate for the year should be acceptable for non-dispatchable CHP for the next 8 – 10 years until a renewable over-generation bubble starts to materialize. For dispatchable CHP, a heat rate that reflects fewer operating hours and a higher percentage of peaking generation would be more appropriate. CHP installed on the customer side of the meter to displace utility power purchases should have transmission and distribution losses factored into the displaced grid electricity heat rate.

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25 *See* NYSERDA web site: http://www.nyserda.ny.gov/Funding-Opportunities/Current-Funding-Opportunities/PON-2568-CHP-Acceleration-Program.aspx .

3. *What method should be used to determine the efficiency of displaced thermal resources?*

As pointed out at the Workshop, boilers are optimized for efficiency at full load, but are typically operated at part load. Also, applications with higher quality heat requirements are also challenged to achieve ultra-high efficiencies. We recommend that the default value for avoided boiler efficiency be set at 80% and that lower values be considered for particular sites that can demonstrate actual performance with operating data and that possible efficiency enhancements (economizer, for example) are infeasible or not practical.

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

No new reporting requirements should be imposed on CHP systems. Monitoring and reporting can be prohibitively expensive, particularly for smaller CHP systems under 1 MW. Voluntary or statistical data collection should be encouraged accompanied by State funding support. For smaller systems, utility grade thermal metering should not be required. Select temperature measurements coupled with manufacturer specifications should suffice to calculate useful thermal output.

VI. Energy Commission Staff Proposed Methodology for Estimating Fuel Displacement.

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

The methodology looks reasonable. However, CCDC notes that the 2014 heat rate shown for load following generation is different than the marginal 2014 heat rate currently used by the CPUC and CARB. A comparison of these two approaches is recommended as is the adoption of a common approach by the applicable State agencies. The transmission and distribution loss assumption of 7.8% seems reasonable. In the longer term, most fossil generation will be dispatched to firm renewable generation resulting in more cycling and higher heat rates. CCDC does not feel that decreasing heat rate trends continue for the longer term situation in California.

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

We agree with the methodology employed by the CEC staff. The RPS percentage should not be a factor in determining grid fuel displacement by CHP. Applying an RPS percentage penalty to the marginal generation resource for customer-side-of-the-meter measures inadvertently favors wholesale generation resources over customer sited renewables, efficiency, and CHP, and is contrary to State energy policy. Furthermore, AB 327 decoupled the RPS mandate from a percentage of wholesale power generation.

3. *How could the method be applied to create beneficial comparisons without interfering with existing metrics?*

A consistent State-wide methodology on this issue and energy policy in general is important to end users and energy solution providers who need to plan 10 – 15 years out for prospective energy infrastructure investments.

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.*

For now, the annual average values are sufficient for non-dispatachable CHP. It may be more appropriate to have a value weighted more toward peaking generation for dispatchable CHP. Longer term, when renewable over-generation becomes a reality, an annual average may no longer be adequate and the impact of more frequent cycling on heat rate should be recognized.

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

Yes, the simpler the better.

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

Yes, based on CCDC's understanding of the analysis that outside of the large heat rate difference between peaking and load following, any other more granular segmentation would show relatively small differences.

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

The answer to this question is unclear, as it appears imported electricity was not factored into the analysis.

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

Yes.

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

No, as it does not take into account expected operational changes to natural gas generation over the long term.

Conclusion

CCDC looks forward to working with the CEC and other stakeholders in this proceeding towards memorializing the value of the benefits of CHP and eliminating barriers, such that the State's goals are achieved and California consumers realize the benefits of CHP. To that end, CCDC appreciates the CEC's consideration of these comments and recommendations.

DATED: August 18, 2014 DAY CARTER & MURPHY LLP

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ATTACHMENT

Independent Review of “Onsite Generation in CA: Potential Ratepayer Savings and Key Barriers”

June 11, 2014

Independent Review of "Onsite Generation in CA: Potential Ratepayer Savings and Key Barriers"

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This report was prepared by Aspen Environmental Group (Aspen) as an independent, third-party review of the analysis and conclusions developed by EtaGen Inc., estimating savings to investor-owned utility ratepayers from on-site distributed generation. Catherine Elder, director of Aspen's Energy Resource Economics practice, served as the principal analyst and project manager for this review. She was assisted by Ashley Spalding, who performed the quantitative review of the EtaGen model and contributed to drafting Aspen's report.

In reviewing the EtaGen analysis, Aspen relied on its best professional judgment; any opinion rendered is our own. The study was prepared independently, by Aspen, using its best professional judgment and analysis of publicly-available data. Such data is not within the control of Aspen and we are not responsible for its accuracy. Any use of this report constitutes agreement that Aspen accepts no liability for consequences arising from said use.

Independent Review of
"Onsite Generation in CA: Potential Ratepayer Savings and Key Barriers"

Introduction

EtaGen Inc., (EtaGen) asked Aspen Environmental Group (Aspen) to perform an independent, arms-length review of its "Onsite Generation in CA: Potential Ratepayer Savings and Key Barriers" Analysis. The analysis purports to show that from 2010 through 2013, distributed generation (DG) would have provided enough economic benefit to other ratepayers to more than offset the value of "Departing Load Charges" (DLCs). The goal was to have a third party knowledgeable about California energy policy, utility cost allocation, rates and revenue recovery, and generation dispatch economics review EtaGen's methodology and calculations to give an opinion as to the reasonableness of EtaGen's approach and conclusions.

After a preliminary overview of EtaGen's calculations and presentation to assess general plausibility, Aspen agreed to perform this independent review. The review sought to answer three questions: 1) whether EtaGen's spreadsheet analysis functions correctly; 2) whether the methodology is appropriate; and 3) whether the assumptions are conservative. Aspen's approach to conducting the analysis is described in this report. Our finding, made at the conclusion of our review, is that EtaGen's analysis is sound: the spreadsheet calculations function correctly, the methodology is appropriate, and the assumptions are conservative.

Background

EtaGen is the developer of a new and innovative gas engine architecture for DG applications. The architecture features high electrical efficiency and ultra-low NOx emissions. Its deployment fits squarely within the state's goal of deploying 12,000 MW of DG. In discussions with potential customers, however, EtaGen is finding that DLCs are a significant economic barrier to the installation of DG projects. Non-bypassable charges (NBCs) are charges assessed by investor-owned utilities (IOUs) on a per kilowatt-hour basis to electricity purchased from the grid. They are designed to ensure cost recovery for several types of programs such as public purpose programs and nuclear decommissioning. Current regulations require customers who install DG that is not under a Net Energy Metering (NEM) tariff to pay NBCs for the electricity they generate and consume onsite, even though this energy is not provided by the grid. The argument in support of this policy is that it keeps the NBC cost recovery burden from shifting onto remaining ratepayers of the IOU. This is often referred to as the "DLC Cost Shift." A key consequence of DLCs, however, is that they create an economic hurdle that DG must overcome in order to provide customers a viable return on investment. Furthermore, DLCs provide an additional hurdle for developers of new distributed technologies.

In considering the regulatory reasoning behind DLCs, EtaGen hypothesized that DG might provide a greater benefit to all ratepayers than the DLC Cost Shift. EtaGen set out to quantify the potential change that could occur in the wholesale market price of electricity as a result of the deployment of DG. While there a numerous benefits provided by DG, EtaGen focused on quantifying the economic benefits for CAISO market energy prices and avoided Transmission and Distribution (T&D) costs utilizing historical data. EtaGen then compared these cost-savings to the DLC Cost Shift. The end result confirms EtaGen's hypothesis that the reduction in the market prices and the avoided T&D costs provided by DG is more than enough to compensate ratepayers for the DLC Cost Shift.

Summary/Snapshot of the EtaGen Calculations

EtaGen performed its calculations in a Microsoft Excel workbook. The essence of their analysis is to measure the change in electricity prices that ratepayers of the IOUs would have experienced as a result of a reduction in demand on the grid caused by other customers installing DG. EtaGen does not attempt to estimate IOU avoided energy cost for a future period (which requires a significant number of assumptions and much more detailed modeling to predict the future resources and loads). Instead, EtaGen utilizes historical CAISO day ahead hourly (DAH) energy price and demand data for 2010 through 2013 to estimate the impact that 500 MW of demand reduction would have had on energy prices assuming 500 MW of DG been added.[1] In estimating this price change, EtaGen includes a conservative adjustment factor to account for the T&D line losses that are avoided by the DG.

After estimating the change in CAISO energy prices, the analysis then relies on publicly available data reported by the IOUs to FERC that details their annual electricity purchases in 2010 through 2013. This data is used to estimate how the changes in market energy prices would have affected IOU energy costs. The analysis quantifies the IOU cost savings by applying the changes in market energy prices to each IOU's purchases directly from the CAISO market and purchases from qualifying facilities (QFs). Lastly, EtaGen accounts for the value of avoided T&D costs by using published values from a 2010 California Public Utilities Commission decision on the cost-effectiveness of demand response activities.

Aspen Analysis and Findings

Aspen reviewed the EtaGen DG benefits calculations, the associated presentation slide deck explaining the calculations and results, and met with EtaGen to ask clarifying questions. The agreed upon scope for this independent review was to confirm the following: 1) does the Excel spreadsheet function correctly; 2) is the methodology appropriate; and 3) are the assumptions conservative.

Model Functions Correctly

Aspen carefully reviewed the Excel workbook and concluded that it functions correctly. We found that the formulas contained in the workbook are correctly implemented. We thoroughly examined the formulas in the workbook and have confirmed that there are no typos or computational errors.

A key portion of EtaGen's calculations rely on a series of regression equations for each month to estimate how energy prices respond to changes in the DAH demand. The calculations used to

[1] As indicated later herein, the quantity of DG assumed installed and associated IOU load reduction is an input the user can change. EtaGen evaluated several different levels of DG but their main presentation focuses on the installation of 500 MW.

determine the regression coefficient estimates are contained in a separate Excel workbook, but Aspen confirmed the energy price regression results via spot checks in which we took the underlying data and were able to independently replicate the regression equation and obtain the same coefficient estimates as in the separate workbook.

EtaGen also uses Excel's "Goal Seek" function to determine the "demand threshold", which is described in the following section. Goal Seek behaves like an Excel macro, in that the calculations are performed without traceable functions. Aspen therefore tested the Goal Seek function by replicating the needed function set-up parameters. Aspen was able to replicate the same results that EtaGen produced and we can confirm that the output is accurate and repeatable.

The CAISO data EtaGen used as the basis for their calculations in the workbook is from publicly available sources on CAISO's OASIS website. We located these sources and confirmed that that data in the Excel workbook matches values reported in the noted sources. The DLCs are taken from PG&E's E-19 tariff, SCE's TOU-8 tariff, and SDG&E's AL-TOU tariff (all in effect in February 2013). These tariffs are no longer available online, so EtaGen provided Aspen with the tariffs, allowing us to confirm that the values in the tariff are those used in the spreadsheet workbook.

Key to the calculations is data on energy purchases made by the IOUs from the CAISO, the dollar value (or cost) of those CAISO energy purchases, and the QF purchases and costs for each IOU and year from FERC Form 1 (FF1) filings. These values are the sum of individual line items in the FF1s. Aspen located the FF1s and EtaGen provided us with an additional workbook in which the FF1 data was aggregated. We confirmed that the reported FF1 values match those used in their calculations and that any changes to the reported FF1 values contained in the workpapers are reasonable. EtaGen's analysis relies on CAISO energy prices (EP) and DAH demand data for each hour in the four-year test period. We confirmed that raw CAISO data included in the analysis matches CAISO Oasis data. Further we used the "trace dependents" function in Excel to trace all inputs through the model and confirmed that they flow through to the results calculations correctly.

Aspen confirmed that the analysis results are in the right order of magnitude. Aspen did a spot-check of estimated price changes and found that on average, the energy price computed in the workbook decreases by 2 percent in January 2010 as a result of adding 500 MW of DG. The price change and its magnitude relative to the hourly market-clearing price will vary as the price itself varies by month and hour. But generally, we should expect the impact of 500 MW of DG to be small, and the model produces a price change consistent with that expectation. The aggregate savings resulting from this price change are nonetheless substantial because the small price change is applied to a large number of megawatt-hours.

Aspen also confirmed that the results respond appropriately to input changes. Prior versions of the Excel workbook did not account for T&D losses. Aspen tested this by taking the final version of the workbook and setting T&D losses to zero. We were thus able to see that the results with T&D losses set to zero matches those produced by the prior versions of the workbook.

Finally, EtaGen built in sensitivity to allow users to modify the CPUC adopted T&D facility savings. Aspen confirmed that the workbook calculates correctly by reducing the realized savings by 50%. As appropriate, the calculated T&D savings decreased by 50%.

Methodology is Appropriate

The basic approach to EtaGen's analysis is to compare ratepayer system savings from DG to the DLC Cost Shift. The key ratepayer system savings from DG are due to the fact that DG lowers the demand on the grid, which results in lower CAISO market energy prices, lower T&D losses, and avoided T&D facilities costs. In order to compute these savings, the Excel workbook first prepares the raw inputs using the following three steps:

1. *Estimate the change in CAISO energy prices from decreased demand by DG*

The most accurate way to measure the change in electricity price associated with having DG in a given hour would be to rerun the CAISO dispatch algorithm for each hour, with DG added in the proportions assumed for each IOU. Unfortunately, this approach is not feasible. What is feasible, however, is to obtain the data that is publicly-available for the market-clearing price and quantity of megawatts dispatched and sold for every hour, by month, in the four-year historical test period. This data can be used to construct a curve that relates CAISO DAH energy price to DAH system demand (CAISO market-clearing quantity) for all the hours in a given month. This curve then allows one to mathematically calculate the change in price that would occur in any given hour of a month for a given change in system demand in the CAISO market.

In economic terms, the analysis assumes that short-term supply of electricity in the CAISO wholesale market is fixed. The installation of a new DG technology is a change independent of any change in price and reduces demand at every price. Therefore, the analysis treats the installation of DG as a shift in the demand curve. Another way of thinking about this is to realize that a demand change caused by the installation of DG is not a demand changed caused by an exogenous price change, which is treated differently in economic analyses.[2]

EtaGen created monthly curves by fitting fourth-order polynomial regression lines to the raw CAISO DAH energy price and system demand data. The monthly regressions set hourly CAISO energy prices as the dependent variable and DAH CAISO demand as the independent variable. By fitting the equation to monthly data, the approach captures enough data points to serve as a reasonable proxy in lieu of re-dispatching the entire CAISO market. EtaGen used fourth-order polynomial regressions for two reasons: 1) to sufficiently capture the three major inflection points of a typical supply stack in the CAISO market that represent the transitions between resource groups (i.e., renewables/nuclear, natural gas combined cycles, and natural gas peaker plants), and 2) to use a uniform model for all months that had statistically significantly parameters and could accurately estimate the actual annual costs of electricity in the CAISO market.

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[2] For further background on these differences please refer to, for example, the Instructor's Manual written by Nora Underwood for Pindyck and Rubenfeld's book, *Microeconomics*, at page 7. A copy of the Manual can be found at http://www.slideshare.net/SaraMishelle/pindyck-microeconomics-6ed-solution.

EtaGen's workbook contains the resulting coefficient estimates for the polynomial regression equation for each month. For every hour in a given month of the 2010 through 2013 period, the analysis calculates the change in price that would have occur in that hour if DG had served load, thereby reducing the CAISO system demand. The workbook does this by applying the coefficient estimates for the corresponding month to historical DAH demand and DAH demand less the DG output to compute the pre-DG price and the post-DG price for every hour in the month resulting from reduced market-clearing demand.

As indicated previously, Aspen spot-checked the regression equation results. We also agree that use of the fourth-order polynomial regression results is reasonable. To determine whether or not the fourth-order polynomial is the appropriate functional form to use for the regression equations, EtaGen generated third- and fifth-order polynomial regressions for each month in which the absolute value of the t-statistics of the original equations were less than two. The analysis compares the t-statistics and p-values across the three sets of models. The third- and fifth-order polynomials provide a better fit (i.e., the absolute value of t-statistics for the coefficient estimates are greater than two) for several months during the four-year test period. However, the fourth-order polynomial provides the best fit for the majority of months.

EtaGen also provided the R-squared results. The R-squared statistic represents the percentage of change in the dependent variable that is explained by changes in the independent variable, and it is used to assess the "goodness of fit" or explanatory power of regression equations. The R-squared values range from 0.522 in December 2013 to 0.915 in July 2013, with an average R-squared value across all months and years of 0.770. These results indicate that the polynomial fits better in some months than in others, but overall, an average of 77% confirms a reasonably good fit across the test period.

More importantly, the Excel workbook validates the monthly regression estimates by comparing the reported CAISO load cost to the total cost computed using the estimated pre-DG price. The values differ by less than 0.0000002%, demonstrating that the model reasonably estimates annual costs.

2. *Estimate the amount of IOU savings from lower CAISO market prices*

Estimating these savings relies on calculating how much energy was purchased from the CAISO market in each hour by each of the IOUs and at what price. FERC Form 1 reports the total annual cost and quantity of IOU energy purchases, with a break out of the cost and quantity each IOU purchased from the CAISO and from QFs. It does not provide hourly prices, however. The CAISO reports hourly TAC area demand for each IOU and associated locational marginal prices (LMPs) in each hour. An important aspect of EtaGen's analysis is that it relies on matching each IOU's annual total amount and cost of CAISO energy purchases reported to FERC with the hourly market-clearing quantities and prices reported by CAISO.[3] Put differently, the analysis finds the quantity at which all higher demand can be

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[3] EtaGen also uses the FERC data to determine the following for each IOU and year: 1) the total purchases for each IOU as a percentage of total purchases in their TAC area; 2) the total CAISO purchases for each IOU as a

deemed to be a purchase from the CAISO, after IOU-owned, bi-laterally contracted, and QF generating resources are exhausted.

This is accomplished as follows. EtaGen first assumes that for every year, the ratio of IOU total annual demand to the TAC area total annual demand is constant over all hours in that year. Using this ratio, the analysis establishes a "demand threshold." The demand threshold represents the portion of TAC area demand above which purchases are made from CAISO. The workbook computes different demand thresholds for each IOU for each year, and each threshold is held constant for each year.

The analysis uses the Goal-Seek function and applies two different methods to determine each demand threshold: a "match cost" and "match load" method. The match cost method finds the minimum hourly TAC area demand such that the computed annual cost of IOU CAISO purchases (sum of hourly LMP times the hourly IOU demand in excess of the threshold for all hours in the year) is equal to the annual cost of IOU CAISO purchases reported in FERC Form 1.[4] The match load method finds the minimum hourly TAC area demand such that the computed annual IOU CAISO load (sum of hourly purchases in excess of the threshold for all hours in the year) is equal to the annual IOU CAISO load reported on FERC Form 1. The user can select which method to use in the analysis.[5]

3. *Estimate the amount of IOU Energy Losses from T&D*

DG reduces IOU line losses because it is located at its use point as opposed to being transmitted to its use point. EtaGen does not produce its own estimate of line loss. Instead, it compiled a range of line loss percentage estimates from the CPUC, EPA and CEC and selected a value at the low end of this range, 6 percent. The analysis defines the load displaced by DG as the DG output divided by one minus the percentage of T&D losses.

The data obtained in the above three steps is used to compute the energy price savings and T&D facilities savings for each year and IOU. All costs and savings computed by EtaGen are in nominal dollars. EtaGen defines energy price savings as the sum of CAISO energy price savings and the QF energy price savings. CAISO energy price savings is equal to the difference between the annual cost of purchasing the remaining electricity load on the ISO market at the pre-DG and post-DG energy prices. The Excel workbook computes CAISO energy price savings as follows:

$$\begin{aligned}&CAISO\ Energy\ Price\ Savings\\&= (Actual\ Demand - Demand\ Threshold - Displaced\ Load)\ X\ (Pre\ DG\ Energy\ Price\\&\qquad\qquad - Post\ DG\ Energy\ Price)\ X\ All\ Hours\end{aligned}$$

percentage of their total purchases; and 3) the total QF purchases for each IOU as a percentage of their total purchases.

[4] The LMPs take into account congestion and other price factors and have to be used here in order to match the computed price times quantity to the annual dollar cost reported in FERC Form 1.

[5] EtaGen uses the match cost method in their main analysis and presentation; however, the difference between the two is less than 5% and does not appreciably alter the analysis results.

Displaced load in each hour is equal to the annual displaced load (i.e. DG capacity adjusted to account for line losses) multiplied by the percentage of capacity assumed to be operating in that hour. The analysis includes five hourly operation cases. The first is the “All Hours” case in which DG operates at 100 percent of capacity in every hour of the day. The “Steady” case assumes DG operates at 100 percent from 8 a.m. to 11 p.m. and 75 percent of capacity from 11 p.m. to 8 a.m. The “Daytime Hours” case assumes DG operates at 100 percent of capacity from 8 a.m. to 7 p.m. and at zero percent of capacity in all other hours. The “Shoulder Hours” case assumes DG operates at 100 percent of capacity from 6 a.m. to 10 a.m. and 5 p.m. to 9 p.m. and at zero percent of capacity in all other hours. The user can select which case to use.[6]

The analysis calculates the QF energy price savings as the product of the amount spent on QF purchases annually, the percent reduction in CAISO energy prices in that year from step 2, the market factor, and the price factors. The workbook defines the market factor as “the fraction of QF contracts of which their energy prices are exposed to market prices (either directly through DAH prices or indexes such as Short Run Avoided Cost that uses forward prices)” and the price factor as “percentage of energy payments QFs exposed to market prices receive out of all payments (not including fixed O&M costs and other potential payments).” The workbook assumes 75% for a market factor and 80% for a price factor.

$$QF\ Energy\ Price\ Savings$$
$$= (Actual\ Cost\ of\ QFs)\ X\ (\%\ CAISO\ Energy\ Price\ Reduction)\ X\ (Market\ Factor)\ X\ (Price\ Factor)$$

EtaGen computes the savings from avoided T&D investment costs for each year and IOU by multiplying the T&D avoided cost adopted by the CPUC, the percent realized savings, and the amount of DG capacity.

$$Avoided\ T\&D\ Cost\ Savings$$
$$= (CPUC\ Avoided\ T\&D\ Cost)\ X\ (DG\ Capacity)\ X\ (\%\ Realized\ Savings)$$

The Excel workbook contains a work sheet titled “Main.” This sheet displays key inputs and results of the analysis. We identified the following items as key inputs to the Excel workbook that can be altered by the end user:

- DG installed capacity added to CA grid (MW);
- T&D loss factor (%);
- Method for determining the demand threshold (load or cost match);
- Household consumption (kWh/month);
- DG distribution among the IOUs; and
- DG operating hours

[6] EtaGen uses the “steady hours” case in their main analysis, but varies the cases in its presentation.

Using the user-defined inputs and those supplied by EtaGen, the Excel workbook produces key outputs for each year of the recorded period, which are subsequently averaged to produce the following composite annual estimates:

- Load displaced by DG (MWh);
- CAISO energy price savings ($/MWh);
- QF energy price savings ($);
- T&D avoided costs ($);
- DLC Cost Shift ($); and
- Average household savings ($/month) to put the net benefit in context.

EtaGen developed two methods to distribute DG capacity across the IOUs: one is based on market-price exposure and the other is demand exposure. As the name implies, the former relies only on the IOU purchases exposed to CAISO market prices. It serves as a continuation of the methodology used in the workbook calculations, which revolve around the portion of IOU purchases exposed to market prices. The Excel workbook computes market price exposure as the four-year average of each utilities' annual ISO and QF purchases divided by the sum of annual QF and ISO purchases across the IOUs.

The demand exposure method simply assumes that customer installation of DG will occur in proportion to IOU demand. Using this logic, the largest IOU would have the most DG because it serves more customers, supplies more energy, and, therefore, is likely to face greater demand for DG technologies. Demand exposure for each IOU is equal to the four-year average of annual IOU total purchases divided by the combined annual IOU total purchases across the IOUs. The two methods set possible bounds for the allocation of DG and allow the end-user to contrast two ways of capturing the impacts of DG on each IOU. The following table summarizes the locational breakdown for two distribution models:

Exposure Model	PG&E	SCE	SDG&E
Market-Price	38%	56%	6%
Demand	48%	43%	9%

Lastly, it is important to note that EtaGen is not attempting in this analysis to replicate or present a full cost-effectiveness test. Instead, EtaGen is trying to address the narrower issue of whether there are financial benefits to IOU ratepayers sufficient to offset the DLC Cost Shift associated with the addition of DG. Furthermore, EtaGen's analysis uses historical data and performs a retrospective cost analysis rather than forward-looking cost analysis. EtaGen is not trying to calculate full avoided cost but instead simply capture the change in market prices that would occur by virtue of DG lowering demand on the grid and in the CAISO market.

Assumptions are Conservative

EtaGen's calculations rely on a number of assumptions but substantially less than the number of assumptions that would have been required to calculate a forward-looking avoided cost or run a production cost model. Aspen examined each of the assumptions and, where possible, their sources, and can concur that they are conservative.

The Excel workbook allows for two reasonable options for allocating the 500 MW of DG across the IOUs. This prevents the incremental DG from being concentrated in the most favorable IOU.

The analysis adjusts TAC purchases down to the IOU level. The workbook computes the ratio of annual IOU purchases to TAC purchases for each IOU and year. The analysis assumes this ratio is constant across every hour of the year, and uses these ratios to adjust TAC purchases downward in every hour to IOU level purchases for each IOU and study year. This assumption may or may not be strictly correct, but in the absence of publicly available information to the contrary we find it reasonable.

Instead of assuming that all IOU sales are exposed to CAISO market prices, the analysis takes care to assess which portion of IOU sales would be exposed to CAISO market prices and applies the lower CAISO price only to that portion. EtaGen assumes that only the portions of sales in each hour that are greater than the computed demand threshold are purchased on the CAISO market. Further, the analysis assumes that only 75 percent of QF purchases are exposed to market prices and that only 80 percent of the cost of QF purchases is energy cost. This helps to ensure that the resulting savings estimates are not exaggerated. Aspen believes these are reasonable based on the fact that 1) some QFs are still paid a fixed avoided cost rather than a market-based price and 2) payments to QFs historically have also included non-energy components to cover operations and maintenance expense as well as capacity payments. Moreover, these assumptions are changeable by the user.

The analysis is careful not to overestimate T&D line losses. EtaGen compiled a range of reported line loss percentage estimates made by the CPUC, EPA and CEC that have all been, and continue to be, used for policy-making decisions. From those, it selected a value at the low end of this range, 6 percent, to use in the calculations.

Similarly, EtaGen relies on CPUC-adopted figures for T&D avoided investment costs. These were adopted by the CPUC in Decision 10-12-024 ("Decision Adopting a Method for Estimating the Cost-Effectiveness of Demand Response Activities"). These estimated savings continue to be used by the IOUs and the CPUC today. As a conservative measure, the EtaGen workbook allows the user to discount the CPUC-adopted T&D avoided investment costs by changing the value for "% Realized Savings." Thus, the workbook accommodates the idea that there may be situations in which T&D investments may not be avoided.

EtaGen's analysis is in nominal dollars. Aspen deflated the costs and savings for each year using a producer price index that was readily available. The net savings averaged over the four year historical test period does not change by more than 3%. We conclude that this does not appreciably affect the magnitude of EtaGen's results.

The analysis excludes many of the benefits of DG that could be included in a full cost-benefits test. These benefits include, but are not limited to: reduced need for capacity, GHG reduction, job creation, grid security, inertia, blackstart, voltage regulation, reduced congestion prices, reduced CAISO prices to non-IOU participants in CAISO market, and the associated reduction in RPS compliance cost due to lower

IOU sales. The analysis' estimate of savings to utility ratepayers would increase if the excluded quantifiable benefits were included in the workbook.

EtaGen includes five different scenarios for DG operating hours. These scenarios determine the percent of capacity at which DG is operating for each hour of the day. Aspen agrees that the range captured by the operating hours scenarios is reasonable.

The Excel workbook spreads QF purchases and DG output over all hours. This is reasonable because both QF purchases and DG output occur over all hours and many operate on a baseload basis. EtaGen did not, in other words, assume that DG operates solely in the highest-priced hours; thus, the resulting savings to utility ratepayers are spread evenly among high-priced and low-priced hours within a month.

Finally, EtaGen performs sensitivity analysis on the quantity of DG, how the DG is allocated and operates across the IOUs, and in which hours the market purchases might occur. As a result, EtaGen is aware of how changes in the assumptions and the inputs to the workbook alter the results.

Selected Results

The "Main" sheet in the workbook contains a number of tables that display inputs to and output from the analysis. Outputs for each IOU and each year are displayed where available and appropriate. Additionally, the four-year annually averaged outputs for each IOU is included. EtaGen uses the four-year annually averaged outputs for its reported results. The following table is included in the "Main" sheet and displays, among other things, the four-year annually averaged net savings for each IOU when 500 MW of DG are added and distributed amongst the IOUs using the "market-price exposure" method, and when the demand threshold is determined using the "cost-match" method. Net savings is the key output produced by the analysis and is reported in dollars per year. A positive net savings value indicates that the savings measured by the analysis outweigh the DLC Cost Shift. Further, to put the savings in context, annual net savings are converted to average household savings ($/month) at the bottom of the table.

EtaGen Summary of Ratepayer Savings 500 MW Case

Average Annual Results Steady Hours Case	**PG&E 4 yr avg**	**SCE 4 yr avg**	**SDG&E 4 yr avg**
DG Capacity (MW)	190	282	28
DG Load (MWh)	1,474,581	2,188,900	217,301
Displaced Load (MWh)	1,568,703	2,328,617	231,171
FERC Form 1 Energy Data (MWh)			
CAISO TAC Area Total Purchases	105,114,961	105,395,970	21,170,700
IOU Total Purchases	85,899,069	76,022,598	16,472,276
% of CAISO Area Purchases	*82%*	*72%*	*78%*
IOU CAISO Total Purchases	15,673,120	17,112,544	3,039,913
% of IOU Total Purchases	*18%*	*21%*	*19%*
IOU QF Purhcases	12,346,915	24,481,005	1,089,245
% of IOU Total Purchases	*14%*	*33%*	*7%*
Impact of DG ($)			
Savings			
CAISO Energy Price Savings	*$16,614,846*	*$22,327,761*	*$3,281,276*
QF Energy Price Savings	*$11,050,586*	*$25,328,585*	*$1,034,997*
T&D Avoided Cost Savings	*$14,554,754*	*$15,386,898*	*$2,093,619*
Total Savings	$42,220,186	$63,043,244	$6,409,892
Costs			
DLC Cost Shift	$27,618,897	$34,037,390	$2,394,655
Net Savings	**$14,601,289**	**$29,005,853**	**$4,015,237**
Avg Household Savings ($/month)			
at 500 kW/mohth	**$0.087**	**$0.191**	**$0.124**

Source: EtaGen Excel Workbook

Conclusion

Aspen reviewed the methodology, the workbook calculations, and the assumptions EtaGen used in its analysis. We conclude that the methodology is sound. We find the workbook calculations to be implemented correctly (i.e., that the workbook functions as intended) and the assumptions EtaGen used to be conservative.