**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 ETAGEN FOLLOWING THE JULY 14, 2014 CALIFORNIA ENERGY COMMISSION COMBINED HEAT AND POWER WORKSHOP

EtaGen appreciates the opportunity to submit these Comments Following the July 14, 2014 California Energy Commission ("CEC") Combined Heat and Power ("CHP") Staff Workshop. EtaGen is an energy start-up merging the aspirations of cleantech with the practicality of tried-and-true materials and technology to revolutionize the way electricity is generated and delivered. By taking a fundamental approach to efficient power generation, EtaGen has eliminated the key constraints of conventional engine architectures and is developing an on-site power generation system that makes categorical leaps in efficiency, reliability, cost, and emissions performance. EtaGen's technology is based on research performed at Stanford University and our financial partners include Khosla Ventures and Bill Gates. EtaGen appreciates the consideration given by CEC staff and the Commission to its comments and recommendations.

Introduction

EtaGen 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."[1] Staff correctly observes that even with programs purporting to encourage CHP, its "development in California has been slow." This proceeding provides a much needed forum for further discussions on the barriers to and developing a methodology to measure and properly value the benefits of CHP. Following are EtaGen's responses to the Questions for Stakeholders, with focus being primarily on "small" CHP systems (i.e., systems less than 20 MW).

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1 Notice of Staff Workshop on CHP.

Comments

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?

1. Reduced CAISO demand
2. Reduced CAISO congestion prices
3. Reduced CAISO loss prices
4. Reduced utility capacity requirements
5. Reduced transmission and distribution (T&D) costs
6. GHG savings
7. Grid resiliency
8. Grid security

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

From our conversation with CAISO, they have expressed a desire to have control of all generating units on the grid in order to balance supply and demand, especially with the growing penetration of intermittent renewables. One of the concerns expressed to us is oversupply of electricity from intermittent renewables behind certain buses where there is not enough load to consume the generation (this occurs only a few hours per year, at most, and can result in negative pricing at some nodes in the CAISO wholesale market). Certain types and applications of CHP and other fuel-based distributed generation (DG) could actually help in theses over generation events because of such systems' ability to turn off, thereby increasing a facilities electricity demand and providing a place for the oversupply of electricity. This type of customer response is the inverse of traditional demand response, referred to here as "virtual demand response." The CAISO and utilities could develop virtual demand response programs for CHP and DG customers to help manage grid oversupply.

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?

We are not intimately familiar with all the types and sources of data are currently available. However, the types of information that could be useful to more completely and accurately analyze the benefits and costs of CHP would include: granular energy and thermal load data before and after the installation of CHP, the efficiency of displaced boilers, the types of prime mover installed (e.g., engine, turbine, fuel cell), and the sizing and operating characteristics of the CHP unit (e.g., operating hours and quantities produced). Additionally, more clarity into the CAISO dispatch model and the quantity and timing of IOU electricity purchases in the wholesale market would better enable quantifying the marginal benefits of CHP.

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

The utilities could develop an "opt-in" program for CHP customers to share this data with State agencies (with or without an organization's information attached), the utilities could provide more clarity into their wholesale market purchases (quantity, timing, and price), and the CAISO could be more transparent with its dispatch model (or perhaps dedicate resources to helping the CEC analyses).

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

A significant benefit of CHP that not been recognized by the State is the marginal impact CHP has on wholesale energy prices and capacity payments. CHP reduces the demand on the system and has a downward force on market prices and capacity payments. The New England ISO has recognized these benefits of demand reduction on energy and capacity prices, referred to as Demand-Reduction-Induced Price Effects (DRIPE), and report updated values in bi-annual reports titled "Avoided Energy Supply Costs in New England" produced by Synapse Economics, Inc. New England ISO has both an open energy and capacity market, which makes it possible to quantify the impacts on both energy and capacity prices. Since CA only has an open energy market, it will be difficult to quantify the impacts that CHP has on capacity prices without more transparency into the bi-lateral contract proceedings (particularly with respect to the value of capacity). More transparency into the quantities and timing of IOU energy purchases from CAISO and bi-lateral contract terms would better enable quantifying the impact that changes in market prices have on IOU and ratepayer costs.

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

NA

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

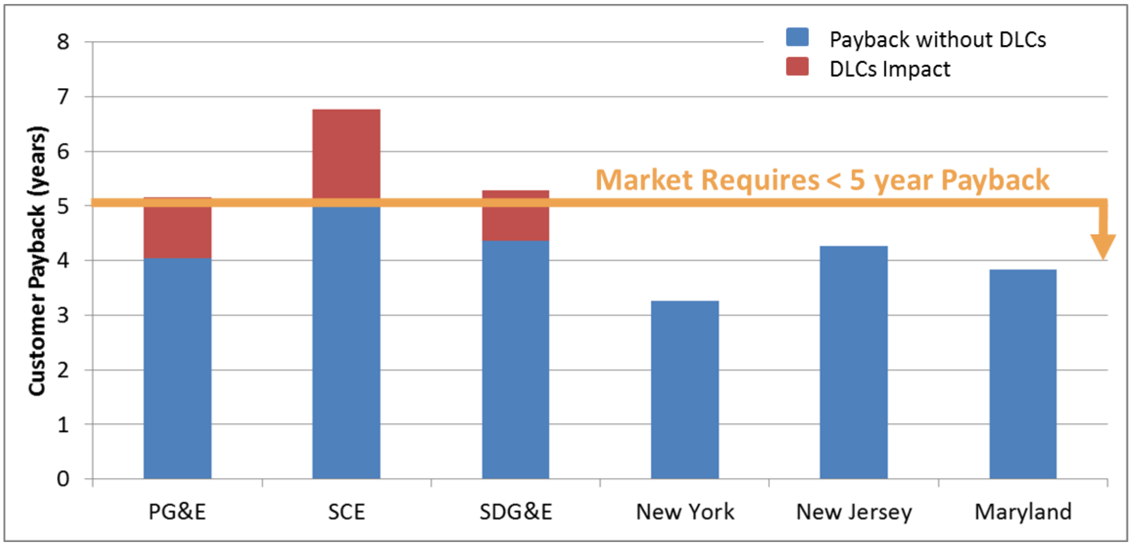
1. What are the most significant economic factors that contribute to the decision by a public or private developer to invest in CHP (e.g. upfront cost, ongoing operation and maintenance, electricity rates, price of natural gas, internal business decision making processes)?

The most significant economic factors that contribute to the decision to invest in CHP are project economic return, often measured in after-tax internal rate of return (IRR), and customer capital constraints. Each type of customer typically has a different required IRR in order to decide to install CHP. The variance in required IRR is due to customers having differing costs of capital and risk profiles. We have found that private-sector customers are especially sensitive to project IRR and less concerned with the amount of GHG savings (they typically just don't want to be worse than their status quo). The three major drivers of a project's IRR, in order of significance, are capital cost, energy cost savings, and O&M costs. Where energy cost savings is function of system performance (electrical and overall efficiency) and operation (e.g., operating times), utility tariff prices and structure, and displaced boiler efficiency.

Capital cost is not only the largest driver in a project's IRR, but it is also the key issue for customers with capital constraints. There are often cases where a project could be projected to meet a customer's required IRR threshold, but the customer doesn't have the cash available to make the initial investment. Leasing or power purchase agreements can often be utilized when this occurs. However, these agreements add a layer of complexity because separate sources of funding are typically required to fund the agreements, and these sources of the capital require their own rate of return (essentially adding another middle man). Access to cheap sources of capital (i.e., from sources with low costs of capital) is where utilities and the State could play a role (e.g., through a "green bank").

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

Departing load charges (DLCs) are the largest barrier to the economic viability of CHP projects in CA. According to our market research and general industry knowledge, customers are typically looking for a 15-25% IRR in order to install CHP. This after-tax IRR range roughly corresponds to a before-tax simple payback between 5 and 3 years. The figure below shows the simple payback periods for a typical CHP installation in the three major CA IOUs, New York's Con Edison, New Jersey's JCPL, and Maryland's PEPCO. The blue bars in the figure represent the payback in the absence of DLCs (but including standby charges), the red bars represent the incremental costs from DLCs, and the sum of all the bars is the total payback. The model uses each IOU's actual electricity and gas tariffs, which accounts for the differing rates and charges across the IOUs and the higher gas prices in the east coast states.



Model Assumptions: $3,000/kW installed cost, 25 $/MWh O&M costs, 35% electrical efficiency, 90% overall efficiency, 85% displaced boiler efficiency, 3% fuel price escalator, 3% grid price escalator, 2% O&M escalator

Tariffs: PG&E: E-19 and G-EG, SCE: TOU-8 A and SoCalGas GTI, SDG&E: AL-TOU and GTNC, NY: ConEd Sch 9 Rate 1 and Rider H, NJ: JCPL GS < 500 kW and NJNG DGC, MD: PEPCO MGT LVII and WGL Rate 4.

Note: This figure is different than the one shown in the presentation of our analysis, which was run using different input parameters that are specific to EtaGen's technology.

The figure illustrates that the CA IOUs are the only IOUs that apply DLCs and that a CHP project in all of the IOUs analyzed would have provided less than a 5 year payback in the absence of DLCs. However, DLCs in the three CA IOUs increase the payback above the 5 year threshold, essentially making it economically difficult to justify CHP projects in CA. DLCs add approximately 1.1, 1.6, and 0.9 years to the payback period in PG&E, SCE, and SDG&E, respectively. The existence of DLCs in CA is the economic equivalent to having roughly a 60-90% additional sales tax on CHP equipment, which is more than two to three times the current SGIP incentive.[2]

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

EtaGen recently completed an analysis on this very topic. The analysis was third-party validated by Aspen Environmental Group and funded by EtaGen, California Clean DG Coalition, and Southern

[2] It is equivalent to adding approximately $1,000-1,500/kW to the capital cost of a CHP installation. We assumed a total installed cost of $3,000/kW, with the CHP equipment costing $1,650/kW, and the remainder being installation costs and regular sales tax. The current SGIP incentive for CHP is $480/kW.

California Gas Company. The analysis presentation and validation report was attached along with these comments and can be made available upon request via info@etagen.com.

The impetus for our analysis began after first realizing the economic barriers caused by DLCs and then discovering that the main argument in support of DLCs is that they keep the cost recovery burden of nonbypassable charges (NBCs) from shifting onto remaining ratepayers of the IOU (referred to here as the "DLC cost shift").[3] The DLC cost shift is due to the fact that the programs that NBCs and DLCs fund have statutorily mandated amounts that must be collect annually. As a result, when a customer installs CHP they reduce the amount of electricity they purchase from the grid, and therefore they reduce the amount of NBCs collected by utilities. If DLCs are not collected, then the CHP customer creates a burden on other ratepayers (as well as themselves) because the rate of the NBCs will need to increase in order to make the funds whole. In considering this regulatory reasoning behind DLCs, we realized that it only considers one side of the equation and does not account for the various cost-saving benefits provided by CHP. The goal of our analysis was to answer one key question: Are the cost-saving benefits provided by CHP greater than the DLC cost shift? If the answer to this question was yes, then CHP actually provides a net cost-savings to all ratepayers.

While there a numerous benefits provided by CHP, we wanted to be conservative and consider only quantifiable benefits. As such, our analysis used historical data to quantify the economic benefits on CAISO market energy prices and avoided T&D costs. We then compared these cost-savings to the DLC cost shift. The end result confirmed our initial hypothesis that the reduction in the market prices and the avoided T&D costs provided by CHP is more than enough to compensate ratepayers for the DLC cost shift.

The essence of our analysis was 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 CHP (or more generally, non-exporting DG). We did 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, we utilized historical CAISO day ahead hourly (DAH) energy price and demand data for 2010 through 2013 to estimate the impact that a demand reduction would have had on energy prices assuming CHP had been added to the system. In estimating this price change, we also included a conservative adjustment factor to account for the T&D line losses that are avoided by the CHP (6%).

[3] It is important to understand that DLCs are simply NBCs that are applied to electricity generated and consumed onsite. They are charged at the same rates that NBCs are charged at for electricity purchased from the grid.

After estimating the change in CAISO energy prices, the analysis then relied on publicly available data reported by the IOUs to FERC that details their annual electricity purchases in 2010 through 2013. This data was used to estimate how the changes in market energy prices would have affected IOU energy costs. The analysis quantified 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, we account 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.[4]

Selected results from our analysis are shown in the table below. These "base case" results were for 500 MW of DG operating with an 89% capacity factor distributed across the three IOUs. The results of our analysis show that over the four years analyzed each of the IOUs would have experienced a larger savings from lower CAISO energy prices, lower energy losses, and avoided T&D costs than the DLC cost shift. PG&E, SCE, and SDG&E would have saved $14.6M, $29M, and $4M per year from 2010 through 2013, respectively. This savings equates to an average household savings of approximately 9-19 cents/month. Additional results and information on our analysis can be found in the attached presentation.

After presenting our analysis to several key stakeholders, including the CPUC, CEC, and CAISO, EtaGen hired Aspen Environmental Group to perform a third-party validation of our analysis. The goal of this activity was to confirm that the model's calculations function correctly, the methodology is appropriate, and the assumptions employed are conservative. The following is an excerpt from Aspen's final report:

> "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. "

It is important to note that our analysis makes conservative assumptions and only quantifies the value of changes to the DAH wholesale energy prices, reduced energy losses, and avoided T&D costs. We did not include other value of other tangible benefits such as: reduction in wholesale energy congestion prices, changes in real time energy prices, impact on future capacity requirements, impact on non-IOU customers that purchase in the CAISO market, environmental benefits, and grid resiliency

[4] Decision 10-12-024: "Decision Adopting a Method for Estimating the Cost-Effectiveness of Demand Response Activities"

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*
`	$42,220,186	$63,043,244	$6,409,892
Costs			
DLC Cost Shift	$27,618,897	$34,037,390	$2,394,655
Net Savings w/ T&D Avoided Cost	**$14,601,289**	**$29,005,853**	**$4,015,237**
Net Savings w/o T&D Avoided Cost	*$46,535*	*$13,618,956*	*$1,921,618*
Rate Change ($/MWh)	$0.17	$0.39	$0.25
Avg Household Savings ($/month)			
at 500 kW/mohth	**$0.087**	**$0.191**	**$0.124**

and security benefits. We believe that had these other benefits been included, the net savings to all ratepayers would be substantially larger than those shown above.

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

More studies similar to the one performed by EtaGen are needed to better quantify the true benefits and costs of CHP. While our analysis is just one study, the results are significant enough to warrant additional work.

In subsequent conversation with the three IOUs since our analysis was made public, there have been two common themes that would benefit from being addressed in a public setting. None of the IOUs have discredited our methodology or analysis (in fact, one has concluded that "this model is conceptually and structurally sound"), however, the they have expressed concern that our values for avoided T&D costs are too high and that the results "might" not be indicative of future savings. Although we used avoided T&D cost values from a published CPUC decision, the IOUs suggest that not all of those savings would actually materialize. We encourage the discussion around what is the appropriate value for avoided T&D costs. It should be noted, however, that our analysis shows there is still a net savings when not assigning any value to avoided T&D costs. Our retrospective analysis showed that there was the potential for cost savings had there been a reduction in demand in 2010 through 2013. Our analysis does not attempt to predict potential future savings from CHP. We see that there could be value in performing such analysis with input from key industry stakeholders.

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

Exit fees such as DLCs, which continue for the life of a CHP system, are <u>not</u> appropriate. As discussed in our answer to the previous question, the analysis performed by EtaGen and validated by Aspen indicates that the ratepayer savings from a demand reduction by CHP outweighs the ratepayer burden of the DLC cost shift (even without account for any benefit from avoided T&D costs). For this reason, we strongly believe that exit fees are <u>not</u> appropriate for new CHP installations.

Several CA state agencies have expressed concerns around providing "exemptions" from DLCs. We have issues with the expressed concerns for several reasons.

First, we believe that the entire DLC issue and debate has been fraught with misinformation, beginning with the concept that the removal of DLCs is an "exemption." We contend that the term exemption itself is, in fact, incorrect and misleading because facilities would still be paying all applicable nonbypassable charges (NBCs) based on electricity they consumes from the grid. It is understandable that certain agencies are hesitant to provide "exemptions" from any fees for benefit of private businesses, however, DLCs are simply NBCs that are applied to electricity generated and consumed onsite. When viewed in this reality, the removal of DLCs is not an exemption, but rather a fair assessment of existing utility-applied fees.

Second, a major concern around removing DLCs is that it will result in a cost shift to non-participating ratepayers. There are three key points to be made on this concern.

1. The NBC/DLC structure is inherently flawed. Because of the inherent structure of how NBCs are collected (i.e., based on electricity sales), any reduction in demand technically causes a cost (e.g., energy efficiency, demand response, going out of business). However, the state has arbitrarily decided that CHP is the only type of reduction that has to pay DLCs.
2. The cost shift is only one side of the equation. It is true that ratepayers would experience the DLC cost-shift due to their inherent structure. However, this does not take into account the cost-savings benefits provided by CHP (lower energy prices, lower energy losses, and lower T&D costs). As shown in our analysis, the cost-savings benefits from CHP outweigh the DLC cost shift and provide a <u>net cost savings to all ratepayers</u>.

3. NBC/DLC programs would remain fully funded. If NBCs are only collected on electricity purchases from the grid (i.e., DLCs are not collected), all programs the NBCs fund will all still be fully funded, albeit at potentially different rates.

Third, technologies that are eligible for net-energy-metering (NEM) tariffs do not pay DLCs (they pay NBCs based on "net" electricity consumption from the grid). Additionally, NEM eligible technologies do not pay standby charges and they also benefit from preferential interconnection regulations. The CHP community simply requests equal treatment on how NBCs are assessed.

Last, we have found no other state besides CA that allows IOU's to assess NBCs on electricity produced and consumed onsite. In particular, some states with comparably high electricity rates and environmental goals that do not allow this practice include: NY, CT, VT, NJ, PA, MD, HI, and AK. IOU's in the other states ensure CHP technologies pay for their use of grid infrastructure through demand and standby charges (as the CA utilities already do) and that sites pay their fair share of public purpose charges for the grid based on their actual consumption from the grid only (whereas CA utilities charge customers for what they do behind their meter as well).

DLCs create an economic barrier to the installation of CHP in CA, and, as a result, prohibit cost savings to all ratepayers and environmental benefits to all Californians. EtaGen requests that all pertinent State agencies hold public discussions on the topic of DLCs and clearly outline their positions, logic, and reasoning on the topic.

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

NA

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

There currently exists a clear divide between utilities and customer-owned CHP. This divide is inherent to the nature of the utility structure—while utility profit is technically separated from energy sales, it is strongly dependent on the number of fixed assets a utility owns (e.g., poles and wires). Since CHP reduces the need for utility-owned assets, it is therefore a threat to their business model (and, for IOUs, their investors). We believe that regulatory changes are necessary to remedy this inherent divide. A potential option would be to allow utilities to own or help finance (with their low cost of capital) CHP systems located at customer sites. We recommend that the appropriate State agencies hold public discussions on the topic of minimizing utility risk from customer-owned generation.

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?

NA

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

NA

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

NA

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

NA

III. Meeting California's CHP Goals

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

According to a report by ICF International that was sponsored by the CEC, there is adequate economic and technical potential for CHP resources to achieve the State's capacity and GHG goals. [5] However, the study points to several barriers that need to be addressed in order to reach these goals in the desired time frame. The more time that passes until these barriers are removed, the less likely the State can achieve these goals.

2. How should the State meet these goals?

[5] ICF International, "Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment", Consultant Report, CEC-200-2012-002-Rev, June 2012.

Remove barriers to CHP. <u>The most notably barrier that should be removed is DLCs.</u> Other barriers and opportunities cited in the ICF report discussed above that would help meet the State's goals include:

- Revise rates that require customers with CHP to pay both a standby reservation demand charge and additional demand charges for planned outages of the customer's generator. Either-or should be sufficient. Unpredictable load does not have to pay a standby charge, even though the utility must "stand ready" to serve it in the same fashion as generators that rarely fail.
- $50 per kW per year for transmission and distribution capacity deferral payments for non-exporting CHP systems less than 20 MW.
- Cap-and-trade allowance costs for CHP fuel consumption, after avoided boiler fuel is subtracted and is reimbursed, eliminating the effective rise in natural gas fuel costs due to the Cap-and-Trade Program.
- Unified interconnection standards across the IOUs.

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)?

Yes, where appropriate. If certain sectors are good candidates for CHP then the State should do everything in its power to better enable and encourage the installation of new CHP. We believe that removing the barriers to new CHP (especially DLCs) would send the necessary market signals and potentially eliminate the need further procurement requirements/programs. However, if procurement requirements/programs are deemed necessary or desirable, it is of the utmost importance for such requirements/programs to remain technology neutral. The State should set desired performance standards and allow any type of technology that meets those standards to be eligible. The State should not be picking winners and losers among technology, especially with the emergence of new technologies that might not have even been conceive at the time the requirements/programs are established.

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

Sometimes, but not always. Although EtaGen has not yet participated in SGIP, we have heard from others in the industry that the additional interconnection and metering requirements of the program are especially costly for smaller installations and end up significantly reducing the net value of the program's incentive. The State should take into account that economies of scale are significant with CHP, and a requirement that makes physical and economic sense for larger projects might not make sense for smaller projects (or might not even be necessary).

IV. Technology Innovation to Overcome Combined Heat & Power Barriers

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

First and foremost, all CHP technologies would be substantially encouraged by the removal of DLCs for the reasons mentioned above.

Microgrids are valuable to the end user because of the additional source of redundant power supply. In the event of a grid outage, the generator serves load; in the event of a generator outage, the grid serves load. The economic value of this redundancy (and avoided backup generator costs and emissions in some cases) would be justified for substantially more installations if facilities did not have to pay DLCs that discourage these private investments.

Bottoming cycle retrofits that utilize pre-existing heat sources have the exact same environmental impact to the grid and ratepayers as a fully baseloaded solar or wind facility. Such facilities could be privately funded at no cost to ratepayers, but are blocked in many cases by DLCs. Although DLCs would be a first step to enabling more projects of this type (why put a tax on the equivalent of a baseloaded solar facility?), allowing these types of projects to participate in the RPS and be given RECS (since they have the same benefit as renewables) should be considered.

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

There should be standardized protection schemes that installers can use that are IEEE 1547 compliant and that the authority having jurisdiction (AHJ) and utilities are comfortable with. This should be the case for both standard and microgrid applications (i.e., those with the ability to run while the grid is down). Such standardized schemes should include multiple equipment vendor options to facilitate competition and to keep interconnection prices down. There needs to be a level of standardization for the interconnection process for different project types so the process is simplified, transparent, and understood.

V. Electrical Generation Unit and Reference Boiler Efficiency

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

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

Holding thermal utilization and electrical capacity factor constant, the only other thing that might vary is boiler efficiency by project, affecting the offset natural gas required for a given boiler. Generally, larger boilers may be more efficient than smaller boilers (but perhaps not by much). If there is a large enough variation in boiler efficiency across sizes, there might need to be different boiler reference efficiencies depending on the heat the project is offsetting. However, there still might be cases where a small CHP project is offsetting a large boiler. If there is found to be a large enough discrepancy in boiler efficiency across boiler sizes, it would make sense to categorize CHP projects by size (at least) or efficiency of the boiler being offset. Comparisons would then follow based on such a category in conjunction with thermal utilization and electrical capacity factor, both of which will always vary project to project.

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 method proposed by Bryan Neff is an excellent start. CHP units displace the marginal generating resources, and will never displace renewables that are bidding zero into the wholesale marketplace, or that are on rooftops being compensated at the NEM rate. Renewables shouldn't even be factored into the equation until they are being curtailed a high percentage of hours during the year, and that is unlikely to happen even at a 33% RPS. Other comments regarding Bryan Neff's methodology are discussed in section VI.

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

Thermal utilization definitely needs to be taken into account. But the hard part is determining which offset boiler efficiency to use if it is to be standardized. One potential method could be to use a confidential survey of the boiler fleet and average by size. The practice of simple random sampling could give good indicative values of fleet efficiency by boiler size. If there is not much variance between sizes, an overall average would be appropriate.

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

Yes; or at least a large enough simple random sample. Policy decisions would be more easily made by better understanding the utilization factors of the fleet. This data will already be being collected by facilities, so it should not be too onerous of a request.

VI. Energy Commission Staff Proposed Methodology for Estimating Fuel Displacement

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

Bryan Neff's methodology is an excellent start. Our only comment is that we strongly believe that the method inappropriately weights peaking capacity. In its current form, CHP would only get credit for abating peaker heat rates for 2.5% of its MWh generated, because peaking plants make up 2.5% of the natural gas MWh generated annually. We do not think this is appropriate. An effective example is a simplified case where only one CHP project (call it 20 MW) is installed and there is only one peaker plant on the grid (call it 100 MW). That 20 MW CHP project is abating that peaker heat rate every hour the peaking capacity is online. If the peaker has a capacity factor of 10%, but only makes up 2.5% of the natural gas based MWh, the CHP facility is still offsetting peaking capacity (and heat rates) for 10% of the year and therefore 10% of its MWh for a baseloaded facility (not 2.5%). As additional CHP projects and other demand reducing activities come online (energy efficiency, demand response), peaker capacity factors are likely to decrease. As such, we would suggest recalibrating every year based on QFER data, but using peaker capacity factor and not % MWh as the weighting for abated peaker heat rates.

This similarly applies to demand response and other resources that operate during peaking hours. In the example provided in Byan's methodology summary, if demand response is only offsetting peaker hours, it should be credited for 100% peaker heat rate abatement. For the hours demand response operates outside of peak hours, it is abating load following heat rates. This demonstrates that the peaker capacity factor is not really a cap, but a floor for the weighting of abated heat rates. This assumes that a given resource is always available for the peak: a demand response resource operating during peak hours should have 100% peaker heat rate weighting, or a baseload CHP facility or energy efficiency installation should only get credit for the hours of the year that peaking capacity operates (10% in the example above).

A better peaker heat rate floor would be the % of hours of the year that any peaking capacity is online, but in the absence of such data, the maximum peaking capacity factor of the fleet and associated heat rate would be appropriate. This would change annually with varying load growth and demand-side resources.

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

The following answer assumes that the question is asking about the treatment of renewable energy as it affects the methodology, not how useful the methodology is for modeling the fuel displacement of renewables.

As noted above, CHP units displace the marginal generating resources, and will never displace renewables that are 1) bidding zero into the wholesale marketplace or 2) that are on rooftops being compensated at the NEM rate. Renewables should not even be factored into the equation until they are being curtailed a high percentage of hours during the year (in which case marginal CHP creates marginal displacement). Such a scenario is unlikely to happen even at a 33% RPS. It would be easy to quantify the % of renewables curtailed vs the quantity of total renewables to determine when there is significant curtailment.

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

Adjusted as appropriate for the ever changing fuel mix and for proper weighting of peaker heat rate abatement as discussed above, this is the appropriate method for determining displaced fuel consumption from any energy technology that offsets marginal resources.

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.

We do not believe there is enough variance in seasonable heat rate to justify making the method any more complicated. However, this should be confirmed if the data is available.

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

Yes. While use of a single, state-wide heat rate is not perfect, it is sufficient and appropriate for the State's needs.

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

Yes. According to the historical CAISO renewables watch data from January 2010 through March 2014, there was never an hour in which thermal generation was not operating. The minimum amount of thermal generation in this time frame was 2,700 MW. There are two types of NG thermal generation, peakers and combined cycle (load following), so we believe this framework is appropriate.

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

Peak and load following resources imported will likely be similar to those in CA. However, it should be confirmed that percentage of imported electricity from coal resources is sufficiently small such that it can be neglected.

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

We would suggest a previously agreed upon line loss factor that takes into account transmission and distribution. We do not have any issues with the factor used in the study.

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

We agree the floor is reasonable, and note that it should be updated when new combined cycle technologies are installed that can beat the floor.

Conclusion

EtaGen looks forward to working with the CEC and other stakeholders in this proceeding and appreciates the CEC's consideration of our comments and recommendations.

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EtaGen, Inc.

By: _/s/ Adam P. Simpson_______
Adam Simpson, PhD
Co-Founder
EtaGen, Inc
Email: adam.simpson@etagen.com

By: _/s/ John Igo______________
John Igo
Product Manager
EtaGen, Inc
Email: john.igo@etagen.com