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1516 Ninth Street
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RE: Comments from San Diego Gas & Electric on 2012 IEPR Workshop on CHP, February 16, 2012

Comments

SDG&E appreciates the opportunity to respond to the CEC request for stakeholder input on the ICF study, "Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment," (ICF Study) and the general policy direction of the State of California regarding combined heat and power (CHP). While the ICF Study provides unsurprising conclusions that with higher prices C&I customers will install more Megawatts (MW) of CHP, it falls short in providing information useful for policy makers because of flawed assumptions and the scenario approach taken.

The ICF study does raise some useful questions to consider concerning CHP and its relationship to 2050 State GHG reduction goals. The fact that most of the CHP facilities seeking contracts under the QF Settlement are more than 20 years old suggest that CHP facilities built after 2020 have a good chance of still being in service and operating in 2050. Is must-take fossil generation compatible with the State's 2050 goals? Given that the State has very extensive goals for renewable DG (Governor's Office goal of 12,000 MW), that the legislature has codified the AB 32 measure requiring 33 percent renewable electricity by 2020, that a certain amount of dispatchable fossil generation will be needed to provide stability to the electricity grid to accommodate variable renewable resources, and that Investor-owned utilities will acquire 3000 MWs of mostly must-take CHP under the QF Settlement, the 2012 IEPR update should address these multiple state goals together to insure their compatibility and their combined impact on utility rates.

The ICF Study draft as currently written does not provide sufficient information to determine if certain applications or technologies are providing the bulk of the GHG savings or what the cost is per metric ton of GHG reduction with different CHP technologies in different applications. The scenario approach, rather than a supply curve approach, leaves policy makers without key information needed to determine an appropriate long-term role for CHP in GHG reduction. Data from the ICF Study suggest moderate-sized gas turbines (3MW and 10 MW) and microturbines used for CHP provide little or no GHG benefit compared to dispatchable combined cycle generation.[1] What is the distribution of GHG savings within each of the scenarios based on the different technologies and applications across industry? The questions of savings and cost effectiveness of CHP by type of technology and application need to be addressed to help guide policy makers.

In the sections below, SDG&E provides responses to the Energy Commission questions about the ICF Study and CHP policy in general.

I. ICF Report on technical and market potential of CHP including scenario analysis

1) Are there major flaws in the assumptions or errors in the report that would have a significant influence on the findings?

Yes, one assumption that seems to have no basis and that makes it difficult to interpret the results of the ICF Study is the changing market acceptance curve. This change in assumption makes it impossible to tell how much of the change in CHP MWs and GHG savings across scenarios is due to this change-in-behavior assumption and how much is due to the increase in CHP payments/subsidies. At a 4 year payback (a 28% annual return on capital invested for a 20 year project), the assumption in the base case is a 30% acceptance rate by decision-makers while in the medium scenario it is increased to an 80% acceptance rate (Figure 33 at page 113). The results of the medium scenario compared with the base case might be incorrectly interpreted that increasing the prices paid to export power leads to a doubling of the market penetration of CHP (ICF Study conclusions at page 127) when in fact the change in the market acceptance curve may explain most of the change, with export prices having a much smaller effect. <u>The same market acceptance curve should be used in all scenarios to show the effects of policy differences.</u>

A second assumption that should be changed is consideration of combined cycle electric generation as part of CHP in the high case. The consideration of this technology in the high case is misleading since combined cycle generation, as a stand-alone generation technology is not

[1] Tables 40 and 41 show a net heat rate (heat rate less useful thermal) for 2010-2015 of 8,138 for a 3 MW gas turbine, 7,091 for a 10 MW gas turbine and 7,982 for microturbines compared to the heat rate of a baseload combined cycle gas turbine of less than 7,000 btu/kWh.

considered CHP. The 50 percent increase in export CHP in the high case (page 113) due to the assumption that this technology would be added on to conventional CHP is misleading. Adding combined cycle technology to conventional CHP should be deleted from the ICF study. CHP should be sized to maximize use of the onsite thermal energy and not to maximize dispatchable electricity production.[2]

A third assumption in the base and medium cases of the ICF Study is that new CHP will receive no GHG allowances. However, that is an incorrect assumption in many cases. For example, in the case of a production expansion met by expansion of an existing CHP unit or repowering of a CHP unit in energy-intensive trade-exposed (EITE) industry (most manufacturing) will receive added allowances from the Air Resources Board (ARB). As production levels increase, the level of allowances of the existing firm increase proportionately. Second, new CHP at new EITE facilities in should be able to obtain allowances through the benchmarking process. Third, small CHP that produce less than 25,000 MT of GHG (less than 7 MW for a high load factor CHP) are not covered by the cap-and-trade program in 2013-2014 and may not experience the full cap-and-trade costs if ARB provides natural gas utilities with allocated allowances for their small customers. ARB has yet to address the issue of allowances for natural gas utilities, but as regulated entities, any allowances provided by ARB will go to ratepayers if approved by the CPUC. Thus, the assumption of increased costs of the cap and trade program for all major manufacturing industries and the small commercial and industrial applications seems an overly broad assumption. If CHP is a priority for the State, new CHP in facilities that currently have separate heat and power may be revisited in the benchmarking process as ARB reviews this aspect of the regulation in 2012.[3]

A fourth assumption that should be reviewed for its effect is the assumption about use of thermal energy between small systems and large systems. At pages 91 and 127, it states that for small systems, an assumption of 80 percent use of thermal energy is made, while for large systems 90-100 percent of the thermal energy is assumed to be used. This differential seems at odds with the ICF Study's treatment of onsite and export CHP as separate categories. As explained at the workshop, a CHP facility is split into two parts – onsite generation and export generation. The amount of each is based on the sizing of the system, with an onsite system limiting the CHP system size to the level of onsite electricity usage. The export category is not a different facility, but the same facility but with a larger CHP unit to maximize the useful thermal energy produced by the CHP unit. If CHP units are sized to the electric onsite load, it seems more likely that all the thermal energy would be used in comparison to CHP systems sized to meet thermal use. A higher percentage of thermal energy logically should be used if there is an excess thermal need as would be expected for units sized to onsite electrical needs. All CHP should be assumed to have the same level of use of thermal energy; it should not be differentiated by size. Any assumptions of a different level of the effective use of thermal energy used should be based on the industry or application type, not the size of the system.

[2] The CAISO has a market initiative for CHP > 20MW called Regulatory Must-Take Generation for CHP (RMTG). In this initiative, only electric generation sized to meet the host's thermal load will be considered CHP must-take.
[3] Or it may be addressed in the GHG OIR (R.11-03-012) currently underway at the CPUC.

Fifth, the ICF Study does not appear to do much actual analysis of the "judgmental" maximum market participation rates presented in Table 53 (page 114). For example, there does not seem to be any analysis of alternatives to CHP for air conditioning purposes. Given the apparently low load factor and relatively low GHG reductions for CHP used to provide heating and cooling (page 127), it would seem solar photovoltaics (PV) might be a more attractive alternative given the higher GHG reduction associated with solar PV and the match of air conditioning load and solar PV output in most commercial and industrial applications. If the cost effectiveness of solar PV (cost per MT of GHG reduced) is better than CHP in this application, the maximum market participation rate should be reduced accordingly.

There also does not seem to be any analysis behind the maximum participation rates for large CHP to justify a higher maximum participation rate for 5-20 MW and above 20 MW compared to the 1-5 MW group. Large CHP present a number of issues, more than small CHP, including permitting problems, complicated interconnection and distribution system upgrade issues, local air quality issues, and being a target of "NIMBYism." A better assumption is that the maximum participation rate should remain the same or decline as the size of the CHP unit increases above 5 MW.

The ICF Study should also clarify the figures in Table ES-2 are for customer acceptance of CHP and not CHP installations. As the ICF Study acknowledges at page 37, the time period from customer acceptance until a project is built is in the span of years. The discussion of Table ES-2 should provide the caveat that it takes several years for small CHP and up to five years for large CHP from the time of customer acceptance until a CHP unit is operational.

SDG&E also has concerns that the ICF Study has errors. The technical potential numbers in the main text do not match with the detailed findings in the appendices. In Table 6 and Table 10, it shows the combined technical potential for CHP > 20 MW in the SDG&E territory is 217 MW (46 MW in table 6 plus 171 MW in table 10). However, tables C-7 and C-8 show a combined technical potential of only 46.4 MW for the >20 MW category, less than 25 percent of the amount shown in the main text. Further, table C-7 shows the industrial technical potential for >20 MW CHP is in petroleum refining, which appears to be a mistake. The technical potential and market potential for the San Diego service area should be checked for accuracy.

The largest contribution of the ICF Study is to evaluate the GHG saving provided by CHP. The ICF Study correctly provides GHG reductions using the ARB methodology in Figure ES-5 to compare GHG emissions reduction potential based on detailed data on technologies and efficiencies compared to the ARB Scoping plan. However, the study also presents analysis in Figure ES-6 that accounts for the electricity grid becoming less GHG-intensive over time. Unfortunately, the ICF methodology is flawed and the analysis as presented leaves incorrect perceptions. By treating the GHG savings of exported MWhs differently than onsite MWhs, the study leaves the impression that export MWhs are somehow "cleaner" than the onsite CHP production when in fact the GHG emissions are produced by the same CHP unit. The explicit ICF assumption that is incorrect is that onsite production replaces one-third renewable energy due to the 33 percent RPS regulation, but the export MWhs are only replacing fossil generation. This assumption is mistaken; CHP export MWhs should be treated the same as onsite generation. As the State moves toward 2050, dispatchable utility fossil plants will be utilized less to provide baseload energy and more to provide intermediate load energy, ancillary services (regulation up and down, ramping), and load following to accommodate variable must-take resources (variable renewables and non-dispatchable CHP). As pointed out at page 29 of the ICF Study, "CHP may cause wind to back off at night." Export CHP may reduce the amount of renewable energy the electric system can handle and so also can have an impact on renewables. Similar assumptions should be made for both export CHP and onsite use of CHP to provide a more accurate picture of the GHG benefits of CHP. Especially in light of California's 2050 GHG goal and the governor's Office 12,000 MW renewable DG goal, the analysis should recognize that CHP exported to the grid may crowd out distributed renewables as the "degrees of freedom" in resource planning are eliminated.

The ICF Study rightly points out that all measures in the ARB Scoping Plan will have less impact as the State's energy use becomes less GHG intensive. The study states at page 11, "The focus in comparing the efficacy of measures to reduce GHG emissions should be on cost effectiveness." However, the ICF study fails to provide any useful information on the cost per metric ton of GHG reduction from CHP, leaving the policy maker to guess about the level of prices/subsidies that may be appropriate to spur the CHP market. Without any evidence, the ICF Study states, "CHP is less costly than some renewable energy sources providing equivalent emission reductions." (page 11) Such an analysis of the cost effectiveness of CHP could be and should be made part of the ICF Study. The payment to the new efficient CHP in each scenario should be compared to the avoided cost represented by the SRAC rate already calculated in the ICF Study.[4] Payments based on the avoided portion of the retail rate plus the export rate plus an annualized cost of explicit electricity ratepayer incentives would be compared to the SRAC and the result divided by the annual GHG savings. On a levelized basis, the cost per ton of GHG reduction for different CHP technologies, different sized CHP, and in different industries in each of the scenarios could be compared to the cost effectiveness of renewables of $150-$200/MT or to other measures of cost effectiveness such as the cap-and-trade price ceiling. Also, the net impact of various levels of CHP payment and the resulting penetration on utility rates would be useful information for policy makers.

2) Using the various scenarios as a guide for outcomes of regulatory changes, what regulatory changes should the state pursue and why?

As explained in response 1, there is not enough information provided to allow for policy makers to decide on regulatory changes. Since CHP is being pursued primarily for its GHG benefit, the cost per metric ton of GHG in different applications and by different sized CHP should be identified for each of the various scenarios under the same market acceptance assumptions. Each of the "regulatory changes" are simply providing an added incentive/subsidy in order to increase the return for CHP installation and increase the market penetration of CHP. Eliminating standby charges simply provides a utility service to the CHP generator with costs paid for by other customers. Eliminating

[4] The SRAC pricing is a better measure of avoided costs than the AB 1613-specified pricing CHP non-dispatchable as-available power does has the same value as a combined cycle plant that can provide significant load following and ancillary services. .

departing load charges simply shifts the costs for public purpose programs to other customers. Reducing interconnection charges and charges related to system upgrades necessary to safely operate the electricity grid simply socializes the cost burden to other customers. Paying above market rates for exported electricity are costs borne by bundled utility customers and DA customers.

Without a constant market acceptance assumption and a cost per metric ton of reduction by CHP size, it is impossible for policymakers to determine what regulatory changes necessary to encourage CHP market penetration and GHG reduction are just and reasonable for non-participating ratepayers to incur.

3) Is use of the Scoping Plan's GHG reduction accounting method appropriate? If not, provide an alternative.

The ARB Scoping Plan CHP measure has a goal of 6.7 MMT of GHG reductions. This goal needs to be revised just as other GHG reduction measures such as energy efficiency, renewables, and the cap-and-trade program have already been revised.[5] New information including revised economic growth forecasts and technical information on the expectations of GHG reductions that can reasonably be achieved due to the installation of CHP should inform the ARB update. The latter information should be contained in the ICF Study as information for ARB. For that purpose, the ARB Scoping Plan double benchmark approach is useful to provide information for adjusting potential CHP GHG reductions compared to the 2008 CHP measure forecast.

However, moving forward, the ARB should also revisit the double benchmark as boiler efficiency increases beyond 80 percent and as the electricity grid becomes cleaner on the margin. As combined cycle generation replaces less efficient single cycle and steam plant generation on the margin for more hours, the Scoping Plan double benchmark should be updated. Without this reconsideration, installed CHP could become a stranded cost as the less efficient CHP units are forced to shut down to meet more stringent long-term State 2050 GHG goals. The 2012 IEPR Update should investigate whether the long-term GHG goals suggest a more limited role for CHP as a fossil resource.

II. Small and Large CHP Project Development in California

1) What impact will Cap and Trade have on development of non-utility owned CHP? Would having a utility contract change the likelihood of development? How large a factor is the uncertainty of Cap and Trade prices in the decision to install a CHP unit?

It should be recognized that electric utility customers are paying for more than just the cap-and-trade allowance costs to implement AB 32. While CHP installed may incur some allowance costs, they also bypass the costs of other AB 32 programs paid in retail electricity rates such as the cost of the 33 percent RPS - estimated as 1.3 cents per kWh in the ICF study (page 104). And under discussion is a

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[5] It the final cap-and-trade regulation ISOR, Appendix F, Compliance Pathways Analysis, the overall CHP goal was shown as 4.6 MMT.

policy change to allow CHP to avoid paying for public purpose programs by eliminating departing load charges (estimated at 0.8 to 1.2 cents per kWh at page 73). The impact of cap-and-trade cost of allowances should not be looked at in isolation as incentives or disincentives to install CHP under AB 32, all AB 32 costs should be considered.

In addition, the impact of the cap-and-trade price of allowances will depend on ARB and CPUC policies and the situation of the particular facility. EITE industries (most industries likely to use large CHP units) will receive added allowances proportional to expansion. As production levels increase, the level of allowances of the existing firm increase proportionately, so in this situation, the impact of cap-and-trade is small. And for export MWhs, terms under the QF Settlement have the utility pay directly or indirectly for GHG costs incurred.

It is somewhat unclear whether ARB will provide free allowances to new CHP at new facilities under the benchmarking process. And it is still unclear whether the benchmarking process will be changed to provide free allowances for new CHP at existing facilities, not associated with expansion, under the benchmarking process (that is undergoing additional review in 2012), or whether publicly-owned utilities (POUs) or investor-owned utilities (IOUs) will provide allowances for existing electricity customers that choose to install CHP. No decisions have been made by local governing boards of POUs or the CPUC.

Small CHP that produce less than 25,000 MT of GHG (less than 7 MW of high load factor CHP) are not covered by the cap-and-trade program in 2013-2014 and may not experience much impact from cap-and-trade prices if ARB provides natural gas utilities with allocated allowances for their small customers. ARB has yet to address the issue of allowances for natural gas utilities, but as regulated entities, any allocated allowances will go to ratepayers. Thus, if the public policy is to support CHP, regulators will be looking at whether the avoided RPS costs and compensation for GHG costs of exports are enough to spur cost effective CHP or whether allowances should be allocated to CHP for industries that do not already receive an allocation of allowances is needed to encourage CHP.

There is uncertainty about the impact of cap-and-trade prices, but it is more regulatory uncertainty since GHG prices are capped at levels lower than the avoided AB 32 costs expected to be embedded in retail electricity rates and the GHG costs of CHP exports will be recovered directly from utilities or indirectly in sales prices.

Would having a utility contract change the likelihood of CHP development? Yes, an identifiable stream of income will always assist in obtaining financing for new or refurbished CHP units.

2) **Net-metering for CHP is restricted to fuel cells and projects that use biogas. Under these parameters have there been any net-metered CHP projects and what are they? Should net metering be expanded to apply to additional CHP technologies? If so, up to what capacity? Explain.**

Net metering makes little sense since the degree of subsidy is hard to calculate and is not transparent. In addition, the customer subsidy is highly variable depending on the type of customer and type of tariff (TOU or flat). Net metering for CHP on a flat rate allows the CHP owner to sell power in low price hours in the middle of the night when power is not needed for their operation and receive high valued on-peak power from the utility at the same price. Net metering for flat rate customers obliterates the price signal and obscures the level of subsidy. Net metering for CHP should not be considered in order to maintain appropriate price signals and to make clear the level of subsidy; that way consumers and regulators alike can make informed choices.

3) A key feature of AB 1613 is that it allows for export and payment of excess electricity. Will the availability of an AB 1613 feed-in tariff effect your decision to pursue a CHP project in California? Are there any deficiencies in the current implementation of AB 1613? How should they be changed?

The key feature of AB 1613 is not "that it allows for the export and payment of excess electricity" since all qualifying facilities less than 20 MW retain their right to sell excess power under PURPA. The key feature of AB 1613 is providing a long-term contract for the excess power that may improve a developer's ability to obtain financing.

IV. QF Settlement and Infrastructure Planning

Questions for the Investor-owned Utilities

1) How is the portfolio fit of a prospective resource measured? Which attributes of the resource influence its fit into an existing portfolio? Which of these attributes have the greatest influence on portfolio fit?

In the Long-term Procurement Plan proceeding, load forecasts are developed that take into account information on energy efficiency, demand response, direct access and community choice aggregation, distributed CHP and distributed renewables. Existing resources owned or contracted for are then used to meet the load on an hourly basis. Existing resources include nuclear power, renewables, contracted-for CHP that is exporting to the grid, dispatchable fossil generation that provides load following and ancillary services, and other contracted-for generation. Gaps are then determined. Is hourly generation adequate to meet forecasted electricity load? And is there adequate capacity to meet state-imposed resource adequacy requirements. A resource has a portfolio fit if it can be included as a resource to meet energy and capacity needs without significantly impairing the operation of other resources already in the portfolio. For example, in low load hours, there would not be a portfolio fit if new must-take CHP MWhs would require curtailment of already contracted-for CHP MWhs or RPS wind resource energy production or gas generation operating to provide regulation down.[6] Likewise, there would not be a portfolio fit if more fossil resources are needed to

[6] To the extent that the thermal requirements vary, the CHP may be able provide some flexibility. For example, thermal loads may be reduced in the super- off-peak hours if there is no shift working. The operation of a CHP facility could provide a portfolio fit if it did not operate in the low load hours in this example.

provide grid stability due to the addition of more variable renewables (solar and wind). CHP by its design is governed by the thermal energy requirements of the customer facility and is not dispatchable. It could not be used to fill an identified need for load following and thus would not provide a portfolio fit.

Questions for All

1) What is a reasonable planning assumption (single point or range) for the peak capacity value of CHP development during 2013 – 2022?

The information from this workshop is inadequate to answer this question. It is broad question that is more appropriately answered in the context of the broader IEPR update process.

IV. General Questions for All

1) What additional analysis can complement the work completed to support changing CHP development regulations and goals? (i.e. GHG emissions comparison to displaced technologies, etc.)

The additional useful analysis would be to use the data developed in the ICF Study to identify the GHG savings provided by CHP both in terms of the ARB Scoping Plan methodology (as was done) and accounting for the cleaner grid as the State moves toward 2050, but fixing the forward-looking GHG savings to treat export MWhs the same as MWhs used onsite.

Likewise, additional analysis could incorporate cost effectiveness, the cost per metric ton of GHG reduction from different types and sizes of CHP in different applications, so the policy maker can judge the level of incentives that may be appropriate to achieve a given level of CHP market penetration. Ideally, a supply curve of GHG reductions across CHP applications and sizes could be developed to judge the efficacy of any regulations that changes the level of subsidies provided to CHP. Finally, projected rate impacts would be a useful complement in the context of all of California's competing clean electricity goals.

2) Should the state create incentives or penalties to ensure achievement of targets? If so, please suggest program design and implementation.

No. It is unclear whom the incentives and penalties would apply to – state permitting agencies, local governments or utilities if the bulk of the new CHP is largely behind-the-meter. There would be difficulties enforcing penalties on state agencies or governing boards of publicly –owned utilities. The focus should be on setting the right targets in light of the State's 2050 goals, the cost effectiveness of the CHP technology, the desire to avoid stranded costs, and the impact on electricity rates.

3) **What are the near-term and long-term actions needed to achieve 6,500 MW by 2030?**

As stated in response to question 2 above, information for setting an appropriate target should be developed. A goal of 6,500 MW of new, non-dispatchable CHP may not be compatible with the 2050 State GHG goals, 12,000 MW of renewable DG, and the 33 percent RPS under current economic forecasts and expected EE and DR. Before undertaking additional incentives such as state tax incentives or more utility subsidies, the CEC as part of this IEPR update should analyze the interaction of California's multiple policy goals and determine if new CHP can provide some degree of controlled flexibility that variable renewable resources lack. Without coordination and analyses of interrelated mandates, California will find itself out of "degrees of freedom" in resource planning by adopting multiple mandates in isolation of one another.

4) What additional steps could the state take to encourage further development? Prioritize and explain.

Not enough information has been developed to determine the cost per metric ton of GHG reduction by CHP size and application to allow policy makers to determine the level of additional subsidies and the type of preferred subsidies – direct payments, tax breaks, above market pricing, or avoidance of other AB 32 costs.

10) AB 1613 also encourages utilities to take advantage of CHP. Will utilities take advantage of this opportunity? If not, why? What would it take?

Since CHP is located on customer property and is providing thermal and electrical energy to the customer, there are significant barriers to utility participation in owning CHP. In addition, under the QF Settlement new utility-owned CHP does not count toward the MW targets and can count only up to 10 percent of the CHP GHG reduction targets.

Thank you for your consideration.

Yours sincerely,

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