

CHP and the Greening of the Grid

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Abstract: *To the extent that the grid is becoming cleaner and greener, the emissions reduction benefit directly related to CHP has come into question. The paper uses production cost simulations to measure the efficacy of CHP in reducing GHG emissions when the grid, on average, will produce less GHG per MWh in 2021 than it does currently. The simulations indicate that even in California CHP will continue to contribute to the reduction in GHG emissions.*

Introduction

This paper describes the use of an electric production cost simulation model to evaluate the impact of combined heat and power (CHP) on greenhouse gas (GHG) emissions. CHP is a highly efficient process that produces both electricity and thermal energy simultaneously. The thermal energy is usually used for heating water or creating steam for various industrial processes. CHP is more efficient than the separate production of electricity and thermal energy. That is, CHP uses less natural gas to produce the same amounts of electricity and thermal energy than if each were produced separately, Separate Heat and Power (SHP). Since CHP reduces the amount of natural gas used, it reduces the amount of the CO₂ that is emitted.

However, the California electric grid is becoming cleaner and greener. First, new gas-fired, quick-start gas turbines and highly efficient combined cycle units are replacing older, less efficient steam generating units. Gas-fired electricity production in 2021 will require less gas input to produce a MWh of electricity than it currently does. As a result, less CO₂ per MWh will be emitted. Next, California has implemented a stringent renewable portfolio standard (RPS) that mandates, by 2020, 33% of California's electric energy must come from renewable resources. Renewable resources, like wind, solar, and geothermal, do not use fossil fuels to generate electricity. Renewable resources do not emit CO₂ when they produce electricity. To the extent the grid is becoming cleaner and greener, the emissions reduction benefit directly related to CHP has come into question.

While this is a legitimate question, conclusions based on piecemeal comparisons of CHP to a new combined cycle unit or a renewable resource fail to take into account the complex interactions of generation on the California electric grid. The use of a production cost simulation model allows for the interaction of all generation resources, including CHP, to be taken into account. With this tool, one can evaluate the role CHP can play in reducing GHG emissions as the California grid becomes greener.

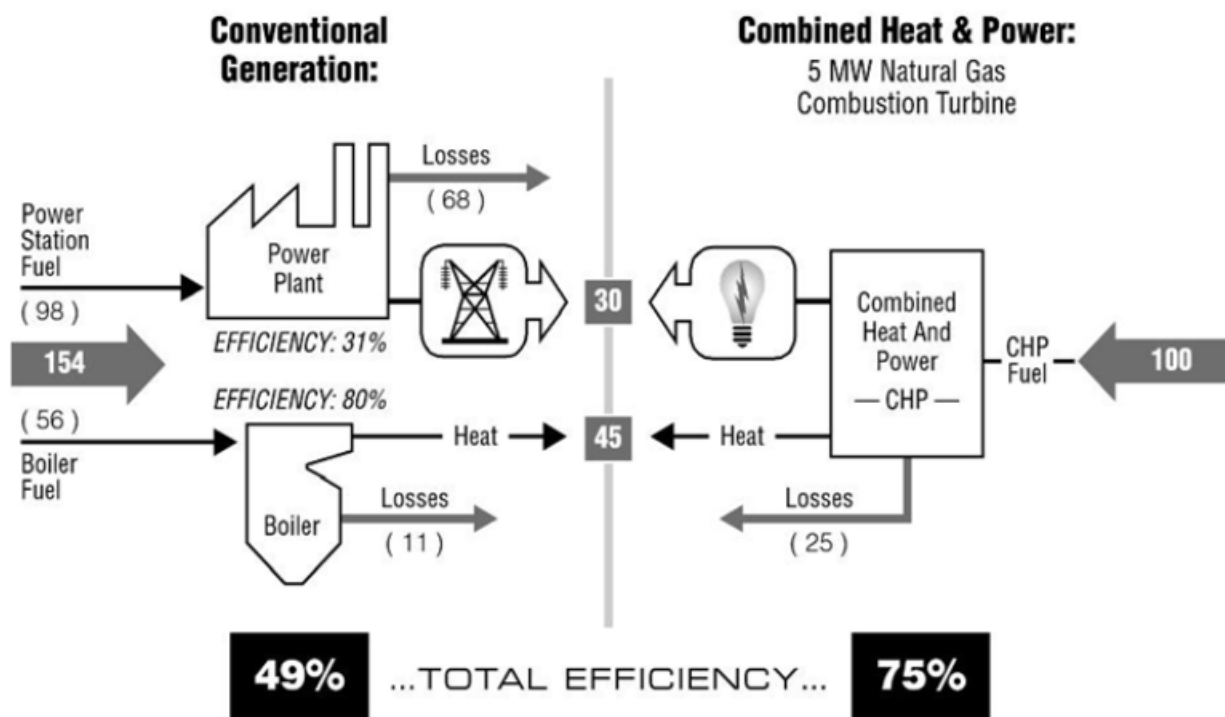
The paper divided into four sections. The first section briefly describes the efficiency and GHG reduction potential associated with CHP. The second section summarizes recent critiques of CHP as a significant actor in reducing GHG. The third section describes the production cost

simulation model and the CHP data used in the simulations to test the validity of the critiques leveled against CHP. The final section presents the results of the production cost simulations with respect to CHP's impact on GHG reduction.

1. CHP Efficiency and GHG Reduction

Figure 1 shows the efficiency benefits of CHP relative to SHP. CHP requires only 100 units of fuel to produce 30 units of electricity and 45 units of thermal output, while SHP requires 154 units of fuel. CHP results in a savings of 54 units of fuel input, which directly translates into GHG emissions reduction (117 pounds CO₂ per MMBTU). In addition to providing both thermal and electric output, CHP's electric output also provides capacity with its energy production, which solar and wind resources do not provide.¹

Figure 1. Combined Heat and Power Efficiency



Source: ICF International, Inc.

Recognizing that the efficiency benefits of CHP directly translate into GHG emissions reductions, there is broad political support for CHP. CHP is viewed as a compliance strategy to reduce GHG emissions under the California Global Warming Solutions Act of 2006 (Assembly Bill 32, or AB 32). In the 2008 AB 32 Scoping Plan, the California Air Resources Board (ARB) adopted a 2020 statewide goal of 4,000 MW of new, efficient CHP. The ARB estimated that this

¹ Wind and solar resources are considered to be variable energy resources (VER), where the amount of energy produced depends on the intensity of the wind and sun, respectively. VER resources have relatively low capacity factors and even lower reliable capacity ratings relative to their nameplate capacities.

CHP measure would reduce 6.7 million metric tons (MMT) of carbon dioxide equivalents (CO₂e) in 2020.² Governor Brown's 2011 Clean Energy Jobs Plan calls for 6,500 MW of new CHP capacity by 2030.³ In August 2012, President Obama issued an Executive Order setting forth a national goal of deploying 40,000 MW of new, cost effective CHP in the United States by the end of 2020.⁴

2. Recent Critiques of the Benefit of CHP for GHG Reduction

The critiques of CHP's ability to reduce CO₂ stem from the recognition that the efficiency and composition of generation resources used to generate power for the California grid are changing. "In addition, continuous improvement in the efficiency of SHP resources and the use of low carbon fuels (such as renewables) reduces the potential for conventional CHP to reduce GHG emissions and is not necessarily captured in the efficiency standards of existing programs." (Williams, P. 6) As a result of the lower CO₂ emissions per MWh of the California grid, it is argued that a more stringent double benchmark standard should be used to evaluate the GHG emissions reduction potential of CHP. The California double benchmark standard should be updated to reflect 2020 improvements in stand-alone boilers with an 85% efficiency rating and a generating unit that is 45% efficient. A 45% efficient generator has a heat rate of 7.537 MMBTU per MWh and emits 0.4 metric tons of CO₂ per MWh. Adjusting the updated double benchmark standard for transmission and distribution losses (6.9%) avoided by CHP and the 33% RPS requirement, only 0.285 metric tons of CO₂ are emitted per MWh, which is equivalent to a generating unit with a heat rate of 5.371 MMBTU per MWh.⁵ (Williams, p. 18) Using this new standard in isolation, devoid of taking account of complex grid interactions, it is not surprising to conclude that CHP will be hard pressed to meet this new standard.

The first critique deals with the significance of the continuous improvement in the efficiency of SHP generating resources.⁶ The greater the efficiency of stand-alone generation, the lower the relative benefits of CHP in reducing GHG emissions. This result can be illustrated by revisiting Figure 1. As shown in Figure 1, a gas-fired generator with an efficiency of 31% (3,413/11,000) has a heat rate of about 11,000 Btu per kWh. One can expect, especially with the California 'once through cooling' (OTC) requirement to remove older natural gas-fired units that require ocean cooling, that new gas-fired units will replace most of the older units. The California grid will become more efficient and cleaner. For example, a new combined cycle unit has a heat rate

² California Air Resources Board, 2008 *Climate Change Scoping Plan, A Framework for Change*, p. 44

³ See: http://gov.ca.gov/docs/Clean_Energy_Plan.pdf

⁴ Office of the Press Secretary, White House Executive Order, August 30, 2012, *Accelerating Investment in Industrial Energy Efficiency*

⁵ $0.285 = [(0.666 + (.666 * 0.069)) * 0.4]$

⁶ Boiler efficiencies vary with size, type, and application. The assumption that stand-alone boilers will improve to 85% efficiency and will penetrate the market to a significant degree is overly optimistic and is not addressed in this analysis; the standard 80% efficiency is used.

of about 7,200 Btu per kWh, or an efficiency of about 47% (3,413/7,200). Replacing the older unit in Figure 1 with a new combined cycle unit, the power station fuel requirement is reduced from 98 to 63 (30/0.47). Total SHP fuel requirement is now 119 (63+56) and total efficiency increases to 63% [(30+45)/119]. CHP savings are now only 19 units. The benefit of CHP to reduce CO₂ emissions would fall from 54 units to 19 units, assuming no improvements in efficiency for CHP prime movers and heat recovery systems.

The second critique recognizes the impact of the RPS. “In the future, increased reliance on renewable electricity generation is expected to result in further decreases in GHG intensity. Without significant improvements in CHP technology, new CHP facilities are unlikely to make a major contribution to lowering future GHG emissions.” (Silsbee, p. 2) GHG intensity is defined as pounds of CO₂ per MWh. Clearly, as the grid incorporates more efficient gas-fired generation resources and renewable energy reaches its 33% goal, the GHG intensity of the California grid will decline.

It is worthwhile to fully explore the relationship between GHG intensity and CHP GHG savings developed in the Silsbee paper because the EPA June 2, 2014 Clean Power Plan (CPP) sets GHG intensity goals for each state. For California, the 2021 target is 574 pounds of CO₂ per MWh. The following is a brief summary of the analysis developed in the Silsbee paper.

GHG savings is defined as $(117 * PGR + EGHG * EO) - 117 * CGR$, where 117 is the pounds of CO₂ in a MMBTU, PGR is the Process Gas Requirement needed by the steam host if the steam were produced in a stand-alone boiler, EGHG is GHG intensity, EO is the annual CHP electric output, and CGR is the gas requirements for the CHP. The term in the parenthesis represents the CO₂ output associated with SHP and the last term is the CO₂ associated with CHP. A positive term indicates that CHP does lead to a reduction in CO₂.

After some algebraic manipulation, GHG savings is now written as

$$(1 - BE/TE) + (EGHG * BE/(3.413 * 117) - BE/TE) * PHR .$$

BE is the stand alone boiler efficiency, TE is CHP efficiency, 3.413 is the BTUs (in millions) needed to produce one MWh at 100% efficiency, and PHR is the power to heat ratio – defined as $(3.413 * EO) / TO$, where TO is thermal output from the CHP in MMBTU.

Table 1 reproduces the results of Silsbee’s Figure 4. It shows the GHG savings associated with SCE’s fleet of CHP. If produced from 80% efficient boilers, the thermal requirements served by these CHP facilities would require about 74 million MMBTU per year. The use of CHP results in saving 3.9 million metric tons (MMT) of GHG emissions. (Silsbee p. 7) The row and column in *italic* have been added to extend the analysis to evaluate the impact of the new EPA CPP.

Table 1. Estimated GHG Savings from SCE's Existing CHP Fleet

	Mid 1990's	Today	2020	New CCGT	EPA CPP
<i>Implied Heat Rate</i>	9,402	8,547	7,692	7,000	4,906
GHG Intensity	1100	1000	900	819	574
Boiler Efficiency	80%	80%	80%	80%	80%
CHP Efficiency	65%	65%	65%	65%	65%
Power-Heat Ratio	0.8	0.8	0.8	0.8	0.8
GHG Savings (%)	55%	39%	23%	10%	-29%
GHG Savings (MMT)	2.2	1.5	0.9	0.4	-1.1

The table shows that as the GHG intensity of the grid declines, the GHG savings from CHP also declines. Using this formulaic approach to evaluate the reduction of GHG emissions, it indicates that under the EPA CPP, CHP would actually increase GHG emissions.

A recent 2012 ICF study makes the following observation (ICF, p. 9):

“Analyzing greenhouse gas emissions reductions from CHP in the context of other statewide reduction programs moving forward concurrently, particularly the Renewables Portfolio Standard targets, results in a declining contribution to greenhouse gas emissions reductions over time. ***The reason for this reduction is that on-site CHP reduces utility demand for electricity. This demand reduction, in turn, reduces the amount of renewable energy capacity needed for utilities to meet their percentage targets. Therefore, with the Renewables Portfolio Standard in place, the avoided utility emissions are only 67 percent of avoided emissions of the marginal fossil fuel electric system.*** For CHP that is exported, there is no reduction in GHG emission benefits because the emissions from the added CHP capacity are included in the estimation of utility greenhouse gas emissions or otherwise accounted for by the purchase of allowances by the export project.”

While this observation on demand reduction is stated in the context of evaluating new CHP, it is important to note that it would apply to any other form of onsite demand reduction. For instance, in evaluating the benefit of GHG emissions reduction due to the reduction in demand related to energy efficiency, there is also a reduction in ***the amount of renewable energy capacity needed for utilities to meet their percentage targets. Therefore, with the Renewables Portfolio Standard in place, the avoided utility emissions are only 67 percent of avoided emissions of the marginal fossil fuel electric system.*** This observation is not unique to CHP.

These critiques of the ability of CHP to reduce GHG emissions are based on engineering type studies, formulas based on generic relationships between CHP factors and GHG intensity, or rule of thumbs that are based on implicit assumptions about the interaction of CHP with the other types of generation resources. This observation was concisely stated in the following statement.

“Estimating the energy and emissions displaced by CHP requires an estimate of the nature of generation displaced by the CHP system. Accurate estimates can be made using a power system dispatch model to determine how emissions for generation in a specific region are impacted by the shift in the system demand curve and generation mix resulting from the addition of new CHP system. However, these models can be complex, costly to run, and are often proprietary. In the absence of a publicly available widely accepted dispatch model, recorded historic emissions rates are used as proxy for avoided grid emissions.” (Williams, p. 14) In essence, this statement forms the basis of this paper. A production cost simulation model is used to take into account the complex interactions of load, CHP, RPS, and all other generation resources anticipated to be in service in 2021 to measure the impact of new CHP on GHG emissions reduction.

3. Describing Production Simulation and the CHP Data

*Production Cost Simulation*⁷

Electric utilities operate energy generation resources, energy storage devices, and load control systems to match electric generation and load on an instantaneous basis. This real-time operation entails using highly sophisticated control systems that match generation levels with load almost instantaneously. It is not analytically necessary to represent this instantaneous level of time detail in performing planning studies that have a time horizon of weeks to years. What is necessary is the ability to handle detailed information in a chronological fashion that allows planning studies to obtain a reasonable approximation of actual system operation.

The production cost simulation model used in the paper is an electric utility/regional pool analysis and accounting system designed for performing planning and operational studies. It models the Western Electric Coordinating Council (WECC). The model contains 23 transmission areas with 2,614 generation units (coal, natural gas, geothermal, solar, wind, and biomass), 63 hydro units, nine pumped storage units, and three battery storage units. It has a chronological structure that accommodates detailed hour-by-hour investigation of the operations of electric utilities and pools. It considers a complex set of operating constraints to simulate the least-cost operation of the utility, or least-bid operation of the pool.

The model’s unit commitment and dispatch logic is designed to mimic “real world” power system hourly operation. This involves minimizing system production cost, enforcing the constraints specified for the system, stations, associated transmission, fuel, and so on. The minimization of the system “production cost” is based on generating station production cost or the station bidding prices. The model determines power flow to equalize the incremental costs of all transmission areas in the system and enforce the power flow constraints. A transmission area may import inexpensive power from its neighbors or export power to replace its neighbor’s expensive power, subject to the limits imposed by available transmission capacity. Each

⁷ Chapter 1: PROSYM and the EPM Modeling System PROSYM User Guide 3 EMDDDB-0010-1302-08

transmission area is considered attached to the main system by a transmission link. Limits and characteristics including capacity by direction, losses, and wheeling, are assigned to the link. Also, a transmission area may carry its own spinning/primary reserve requirement, over and above the overall system requirement.

Load and Generation Data

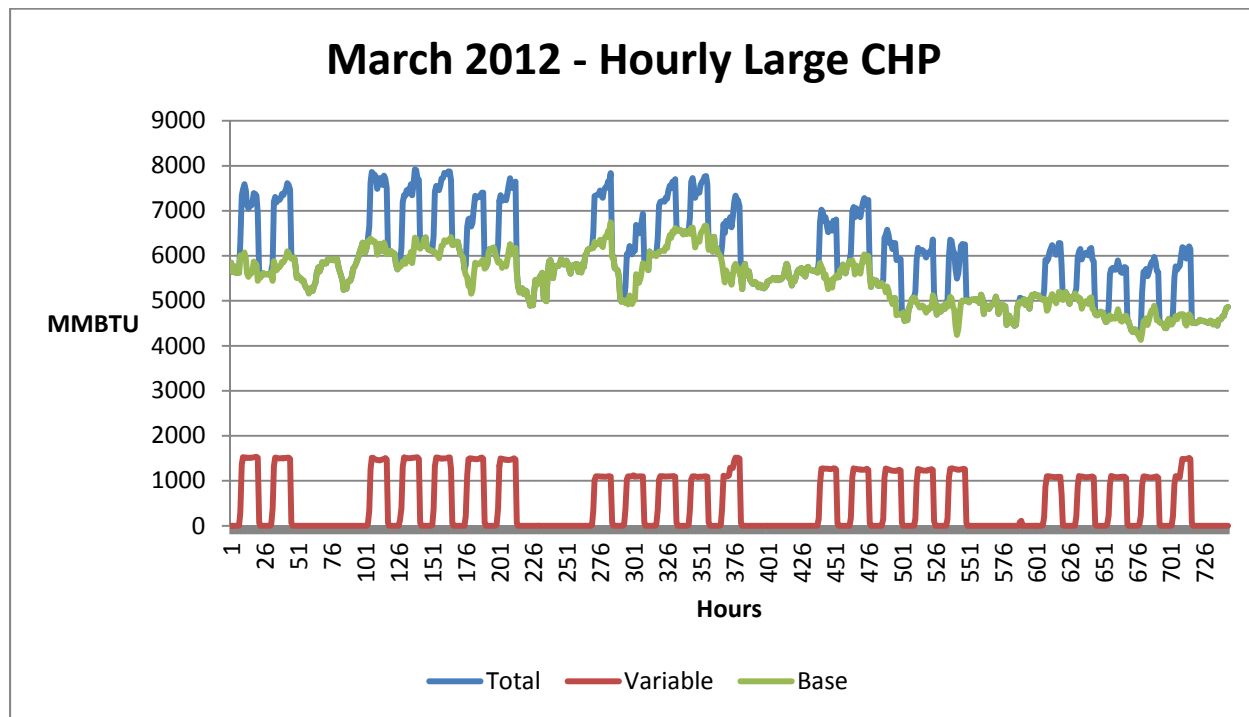
The basic inputs to the model include annual hourly loads, data representing the physical and economic operating characteristics of the electric utility or pool, and ISO rules. The electricity demand forecast used for the simulations was produced by the California Energy Commission (CEC). The December, 2013 California Energy Demand 2014-2024 Final Forecast, Mid Energy Demand scenario, with Mid Additional Achievable Energy Efficiency (AAEE) scenario is used. The Mid Energy with Mid AAEE case for 2021 has a statewide 1-in-2 (normal weather) non-coincident peak of 65,010 MW and a state Net Energy Load (load plus transmission and distribution losses) of 297,108 GWH. AAEE accounts for a reduction in peak load of about 3,300 MW and about a 16,000 GWH reduction in net energy load.

The year 2021 was selected for the simulations because the 33% RPS would be fully implemented. Solar capacity is 21,799 MW, producing 34,839 GWH. Wind capacity is 6,709 MW, producing 20,600 GWH. Of the remaining 13,359 MW of OTC units to be replaced, 11,744 MW are replaced by 2020. The older, less efficient OTC plants are replaced by 1,750 MW of new combined cycle power plants and 2,200 MW of gas turbines. (CPUC)

CHP Data

Large CHP is defined as CHP greater than 20 MW and small CHP is defined as CHP less than or equal to 20 MW. All of the large CHP data used in this analysis are based on the gas throughput for 13 Southern California Gas Company (SoCalGas) customers that represent 895 MW of nameplate capacity. The analysis is conducted on a customer basis because the gas throughput profile showed that the 13 customers could be segregated into two distinct groups. As shown in Chart 1, the first group (Base) operated in all hours of the month. The second group (Variable) did not operate in all the hours of the month. A clear daily and weekly pattern was evident in the Variable group.

Chart 1. Large CHP Load Profile



2012 gas data were used because 2012 was the most recent year that the corresponding electric data for these customers was available from public sources, the California Energy Commission (CEC) Quarterly Fuel and Energy Report (QFER) and the Energy Information Agency (EIA) Form 923.

On an aggregated basis, annual SoCalGas throughput data were about three percent higher than the corresponding QFER gas data, which were about 1.1% higher than the corresponding EIA gas data. Overall, there was a good match between the gas data. The accuracy of the gas data across the other sources is relevant because the QFER and EIA data also contained electric data required for the analysis. However, the QFER and EIA data were only available on a monthly basis. The hourly gas data were used to create an hourly (8,760) annual load shape for the QFER electric data.

The hourly gas throughput for each customer was used to calculate an hourly percent for each month in 2012. This hourly percentage for each month was then multiplied by each customer's QFER monthly electric generation data. The end result is an hourly, electric, load profile for each customer that was aggregated into a single load profile. Confidential information was obtained that provided, on an aggregate basis for the 13 customers, the amount of MWh that was exported to the grid on a monthly basis. On an annual basis, 37.3% of large CHP electric generation was exported to the grid in 2012. Two distinct load shapes were constructed because the non-exported MWh were used to meet internal electric demand and would be subtracted from

the state’s hourly load profile, while the exported MWh would be treated as electric generation resources.

On an annual basis, the QFER electric data (MWh) were about 1.9% higher than the EIA electric data (MWh). Once again, a relatively close fit for both data sources. The EIA data provided the total MMBTU used, the amount of fuel used for electric generation, and the MWh generated by each customer. With this information, the net heat rate, fuel used by all 13 large CHP customers for electric generation divided by the total MWh they produced, was calculated to be 6.1 MMBTU per MWh. This is the heat rate used to dispatch the CHP resources in the production simulation.

The load shape for small CHP was based upon four prototypical CHP systems. The largest of the small CHP systems is gas turbine (5,193 kW) with a weekly operating profile from Monday 6 am through Saturday 6 pm. The next largest small CHP is a large reciprocating gas engine (1,137 kW) with a weekly operating profile of Monday 6 am through Saturday 6 pm. The third small CHP system is a micro turbine (570 kW) that would operate Monday through Saturday, 6 am through 12 pm. The smallest CHP system is a small reciprocating gas engine (100 kW) operating Monday through Saturday, 6 am through 12 pm. Chart 2 shows the hourly aggregated load profile of seven MWh for the small CHP.

Chart 2. Small CHP Load Profile

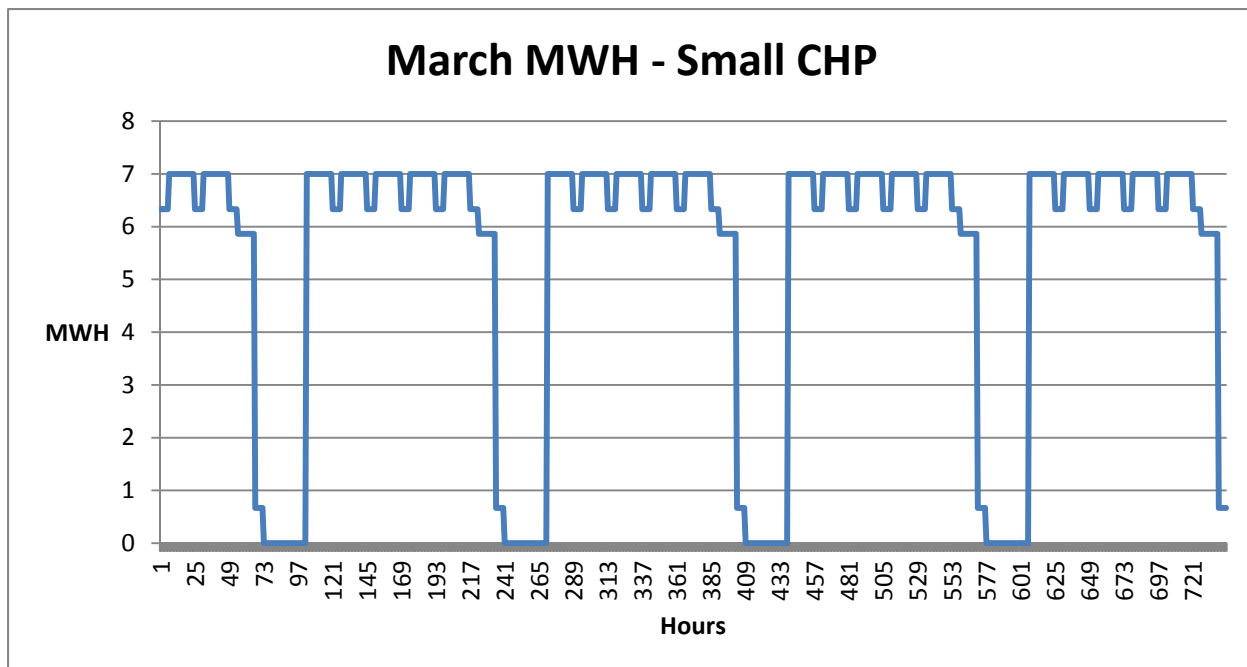


Table 2 provides a more detailed description of each of the four small CHP systems.

Table 2. Small CHP Systems

Type	Total Fuel MMBTU/Hr.	Fuel for Thermal Output MMBTU/Hr.	Capacity Factor	Net Heat Rate BTU/kWh
Gas Turbine	66.3	29.7	78.6%	7,048 [#]
Large Engine	10.64	4.10	71.5%	5,755
Micro Turbine	6.975	2.74	64.4%	7,434
Small Engine	1.26	0.67	64.4%	5,928

$(66.3-29.7)*10^6/5193$

The next step in preparing the CHP data for use in the production simulation model is to determine the amount of new CHP that will come online. For this forecast, the ICF Cumulative Market Penetration Medium Case 2020 is used. Table 3 combines selected data from ICF tables D8-D11.

Table 3. ICF Tables D8-11: Cumulative Market Penetration (MW) Medium Case - 2020

Utility	50-500 kW	500-1000 kW	1 - 5 MW	5-20 MW	>20 MW	Total	% of Total
LADWP	10.30	21.40	58.20	56.60	157.10	303.60	11.37%
PG&E	93.50	56.50	218.40	174.10	972.50	1515.00	56.73%
SCE	10.80	29.20	123.10	132.30	325.40	620.80	23.25%
SCG&E	<u>15.70</u>	<u>14.40</u>	<u>45.60</u>	<u>33.60</u>	<u>121.70</u>	<u>231.00</u>	8.65%
Total	130.30	121.50	445.30	396.60	1576.70	2670.40	
Percent	4.88%	4.55%	16.68%	14.85%	59.04%	100.00%	100.00%

For the small CHP, each prototypical system falls into one of the ICF capacity categories. Each prototypical system was scaled up to meet the forecasted capacity in each ICF capacity category. That is, the small engine (100 kW) was scaled up by 1,303 times to meet the ICF forecast of 130.3 MW, the micro turbine (570 kW) 213, the large engine (1,137 kW) 392, and the gas turbine (5,193 kW) 76 times for a total of 1,093.7 MW.

For the large CHP, the total capacity of the 13 customers is 895 MW. The ICF forecast calls for an increase of 1576.7 MW. This is an increase of 76% of the existing large CHP. Existing Variable nameplate capacity is 212 MW and Base nameplate capacity is 683 MW. The 76% increase in Large CHP was apportioned to each group according to the percentage of existing capacities.

The final step in preparing the CHP data for use in the production simulation model is to take into account transmission and distribution (T&D) losses. CHP that is not exported to the grid reduces energy requirements by an additional 6.9%, average T&D losses. (Williams, p.19) Both the small CHP and the non-export large CHP MWh were increased by 6.9% and subtracted from the state's electric demand. The exported CHP is treated as generation resources that are distributed to the four utilities according to the percentages listed in the last column of Table 3.

4. Production Simulation Results

Two production simulation scenarios were run. Scenario One assumes that the amount of capacity needed to meet the 33% RPS energy requirement is not reduced, even though 2,670 MW of new CHP are added. As a result, the same amount of energy produced by the RPS that is needed to meet the 33% requirement now equals 34.6% of the system energy requirement. Scenario Two assumes that the amount of capacity needed to meet the 33% RPS energy requirement is reduced to compensate for the increase in CHP. That is, the amount of energy produced by the RPS only meets the 33% requirement.

Table 4 shows the amount of fuel used and saved by the non-export portion of CHP. The fuel used to produce non-export CHP energy is calculated outside the production cost simulation. The first column in Table 4 shows the amount of fuel used to produce electric energy solely for internal use. The second column shows the amount of CO₂ created by the CHP. The third column shows the amount of fuel saved because CHP avoids T&D losses. Column four shows the amount of CO₂ saved by avoiding the T&D losses. The fifth column shows the amount of fuel saved by CHP compared to the amount of fuel used by a stand-alone boiler. The last column shows the amount of CO₂ saved due to CHP thermal output. These values do not vary across scenarios.

Table 4. Fuel Use and GHG Related to Non-Export CHP

	Non Export Fuel BCF	Increase in CO ₂ MMT	T&D Fuel Savings BCF	Reduction in CO ₂ MMT	Boiler Fuel Savings BCF	Reduction in CO ₂ MMT
Small CHP	44.67				8.46	0.449
Large CHP	37.40				11.74	0.623
Total	82.07	4.357 ¹	5.66	0.301	20.20	1.072

1. $82.07 * 117 / 2204$, where 117 is pounds per MWh and 2004 pounds per metric ton.

The fuel used to produce export CHP electric energy is included in the total fuel used in the simulation because the energy from the CHP is treated as a resource in the model. Table 5 shows how the addition of CHP interacts with system imports and system Total Fuel use. The first row shows the Base case, before the addition of new CHP. The second row shows the results for Scenario One: imports, import reduction from the Base case, reduction in CO₂ relative to the Base case, total fuel, total fuel reduction from the Base case, and reduction in CO₂ relative to the Base case. The third row shows the same information for Scenario Two.

Table 5. Fuel Use and GHG in Production Simulation Scenarios

Scenarios	Net Imports GWH	Reduction in Imports GWH	Reduction in CO ₂ MMT	Total Fuel BCF	Reduction in Total Fuel BCF	Reduction in CO ₂ MMT
Base	71,457			787.694		
One	62,013	9,444	4.123 ¹	750.832	36.862	1.957 ²
Two	65,149	6,308	2.754	756.958	30.736	1.632

1. $9,444 * 0.428 * 1.02$, where 0.428 is ARB CO₂ tons per MWh from unspecified sources adjusted for 1.02 losses. (ARB P. 71)

2. $36.862 * 117 / 2204$, where 117 is pounds CO₂ per MWh and 2004 pounds per metric ton.

Using data from Tables 4 and 5, the total net CO₂ savings attributable to CHP are calculated for each scenario:

1. Scenario One CO₂ savings: $4.123 + 1.957 + 0.301 + 1.072 - 4.357 = 3.10$ MMT
2. Scenario Two CO₂ savings: $2.754 + 1.632 + 0.301 + 1.072 - 4.357 = 1.40$ MMT

To put the CO₂ savings for each scenario into perspective, the 2008 AB 32 Scoping Plan adopted a 2020 statewide goal of 4,000 MW of new, efficient CHP. The ARB estimated that this CHP increase would reduce 6.7 MMT of CO₂. In the production simulation scenarios, 2,670 MW of new CHP is added, which represents about two-thirds of the ARB 4,000 MW. Two-thirds of the ARB anticipated 6.7 MMT of CO₂ savings is 4.47 MMT.

In Scenario One, CO₂ savings are 3.1 MMT, which is about 69% of the adjusted ARB savings. For Scenario Two, CO₂ savings are 1.4 MMT, which is about 31% of the adjusted ARB savings. The scenarios provide a wide range, roughly between one third and two thirds of the effectiveness of CHP in meeting the ARB's expectations for reducing GHG emissions. Since utilities have an incentive to comply with regulatory requirements, it seems plausible to assume that they will tend to err in procuring more capacity, rather than less, to meet the 33% RPS mandate. That is, if new CHP were to materialize, the utilities probably would not or could not readily reduce signed contracts for renewables. Once contracted for, renewable energy would not be rejected; providing support for results closer to Scenario One, rather than Scenario Two.

While it is plausible to expect that as the grid becomes greener, that is, the GHG intensity per MWh falls, the large reductions in CHP's effectiveness to reduce GHG emissions, as predicted by recent articles cited in this paper, are over stated. Determining the real effectiveness of CHP to reduce GHG emissions requires that new CHP be evaluated within the operational context of the whole electric system. The analysis shows that the emissions reduction capability of CHP, while reduced, is still substantial and should not be dismissed. CHP reduces GHG emissions levels of the California grid and will continue to do so in the future. The 'greening of the grid' will not preclude CHP from remaining an integral part of California's GHG reduction strategy. To paraphrase Mark Twain, the reports of CHP's inability to reduce future GHG emissions is greatly exaggerated.

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