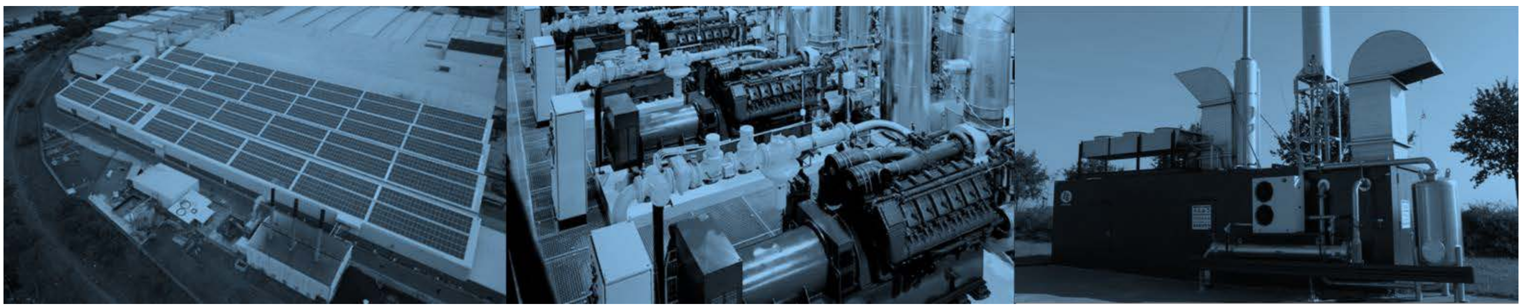

Modeling the Impact of Flexible CHP on California's Future Electric Grid

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U.S. DEPARTMENT OF ENERGY

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Executive Summary

This report examines the potential future impact of flexible combined heat and power (CHP) systems on the electric grid. Unlike current CHP systems that primarily serve on-site electrical loads, flexible CHP systems will serve site loads and also provide a range of services to the grid, including energy, capacity, and ancillary services. Revenue from these grid services, combined with the projected lower installed costs of flexible CHP systems due to technical advances, could improve the value proposition for CHP—increasing CHP deployment on tomorrow's electric grid.

This analysis focuses on the electric grid in California, where flexible resources are becoming increasingly important as more renewables are added to the state's generation mix. Over 24,000 California manufacturing sites were evaluated for potential new CHP deployment, and three scenarios were developed for the California grid in 2024—each with a different amount of CHP:

1. ***Baseline Scenario:*** Assumes a future grid with 33% renewables based on NREL's *Low Carbon Grid Study*. In this scenario, 3,400 MW of existing CHP capacity in California serves site loads with up to 10% of this capacity available to provide grid services.
2. ***Traditional CHP Scenario:*** Adds 1,583 MW of additional CHP capacity (above the Baseline Scenario) at 1,800 sites within California, for a total of 4,983 MW of CHP. These CHP systems mainly serve site loads but can also use up to 10% of their capacity to provide grid services. In this scenario, new CHP units represent 1.6% of California's installed generation capacity.
3. ***Flexible CHP Scenario:*** Adds 3,200 MW of additional CHP capacity (above the Baseline Scenario) installed at 2,700 sites within California. These CHP systems serve site loads with 60% of capacity, and can use the remaining 40% of their capacity to provide grid services. In this scenario, new CHP units account for 3.2% of California's installed generation capacity.

These scenarios reveal the benefits of additional CHP deployment in California, including:

- ***Reduced Grid Operating Costs:*** The total cost to provide energy and reserves in the state decreases modestly, falling 1% in the Traditional CHP scenario and 2% in the Flexible CHP Scenario. These system-wide benefits range from $131M–$265M per year.
- ***Increased Generation Capacity:*** The deployment of additional CHP units provides additional in-state generation capacity that could alleviate the need to construct new centralized power plants in the future, with an estimated capacity value of between $79M and $106M per year.
- ***Lower Industrial Site Energy Costs:*** In both non-baseline scenarios, industrial ratepayers in California who deploy CHP are able to lower their utility bills. In the Traditional CHP scenario, annual site energy cost savings exceed $800M, while in the Flexible CHP scenario, these savings rise to over $1.1B.
- ***Reduction in Grid Stress:*** In both non-baseline scenarios, the future grid relies on flexible CHP to provide energy during periods when the net load is changing rapidly, as when solar generation is dropping off. In the Flexible CHP scenario, CHP nearly eliminates the "high stress hours," during which reserve requirements are unmet or generator/transmission ratings are exceeded.

While the current study focuses on California, flexible CHP systems can deliver benefits to the electric grid across the United States. Flexible CHP could be particularly valuable in states that have a large manufacturing sector, growing deployments of variable renewable resources, and evolving electricity market rules. Future studies will explore the ways in which flexible CHP can strengthen the electric grid in other regions of the country, including the Electric Reliability Council of Texas (ERCOT).

Introduction

Combined heat and power (CHP) systems provide electricity and process heat at more than 4,400 industrial and commercial facilities across the United States.[1] Typically fueled with natural gas, a CHP system combines a prime mover (such as a reciprocating engine) with a generator and heat recovery equipment, allowing operation at very high efficiencies (65–85%).[2] Traditionally, CHP systems are configured to serve local electrical and thermal loads at the sites where they are deployed. Units are sized to ensure a high capacity factor for the equipment, and the electricity generated tends to be utilized on site. Primarily following this paradigm, U.S. CHP units already generate over 12% of the nation's electricity.[3] However, an increasing number of CHP owners, electric system operators, and electric utilities who seek to maximize the value of their investments are exploring how CHP can supply additional services to the electric grid. For example, some CHP units have the potential to provide surplus energy to the grid during peak demand periods more economically than large, centralized peaking plants. In addition to providing energy, CHP can provide other grid services, such as frequency regulation and balancing reserves.[4] Some owners of large CHP units already participate in ancillary services markets, and even small CHP units are occasionally called upon by independent system operators (ISOs) in certain markets (such as the Electric Reliability Council of Texas [ERCOT]) to provide firm capacity during extreme grid events.

By selling energy, ancillary services, or capacity more regularly in the future, CHP systems of all sizes could generate additional revenue and increase system cost effectiveness—particularly in the manufacturing sector, where system owners may find it difficult to generate the necessary return on investment in CHP systems. Greater use of CHP to serve offsite loads and support the electric grid could also provide system-wide benefits, including lower wholesale energy costs, decreased transmission congestion, and improved grid stability. Achieving this future vision will require an evolution of today's market rules, interconnection processes, and CHP technology. This study assumes that this evolution has taken place and explores how additional CHP deployed at manufacturing sites in California might benefit the CHP system owners and the state's electric grid.

California's Need for Grid Support

This study examines the potential impact of additional CHP units deployed at manufacturing sites in California and interconnected to the state's electric grid. Several factors make California a good location for this type of analysis:

- California's industrial customers and grid operators are familiar with CHP. The state has a sizable 8.6 GW base of CHP already installed, due in part to attractive state-level incentives for deployment of distributed generation systems. In addition, the state has a healthy industrial sector that consumes over 50 terawatt hours (TWh) of electricity annually (20% of total statewide

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[1] U.S. Department of Energy (DOE) CHP Installation Database (as of Dec. 31, 2016). www.energy.gov/chp-installs

[2] While various methods can be used to calculate total CHP system efficiency, CHP generally yields a higher combined amount of electricity and useful heat per unit of fuel consumed than can be attained in a separate heat and power (SHP) system. For more information on calculating CHP system efficiency, see U.S. Environmental Protection Agency *Catalog of CHP Technologies.* March 2015.

[3] U.S. Department of Energy. *Combined Heat and Power: A Clean Energy Solution.* August 2012.

[4] In this report, the general term "grid services" refers to any product CHP provides other than energy for site loads. Grid services can include energy, capacity, or ancillary services that are delivered to the electric grid.

electricity consumption),[5] and California's expensive retail electricity rates make many industrial sites attractive for CHP.

- California is at the forefront of renewable generation adoption. The state's aggressive renewable portfolio standard (RPS) targets (33% by 2020 and 50% by 2030)[6] make California an important test bed for the integration of variable renewable generation resources, including wind and solar. As more renewables are added to the state's grid, California's Independent System Operator (CAISO) must ensure that adequate electricity is available when load exceeds renewable supply and must also transfer electricity to other regions or curtail renewable energy that exceeds demand. Flexible generation sources, which have low minimum operating levels and can quickly ramp their output up and down, are becoming increasingly important in enabling CAISO to curb generation during the day and later add generation to match the evening peak of the "duck curve" (shown in Figure 1).[7] Traditionally, large gas-fired turbines have provided this flexibility, but CHP has the potential to contribute as well.

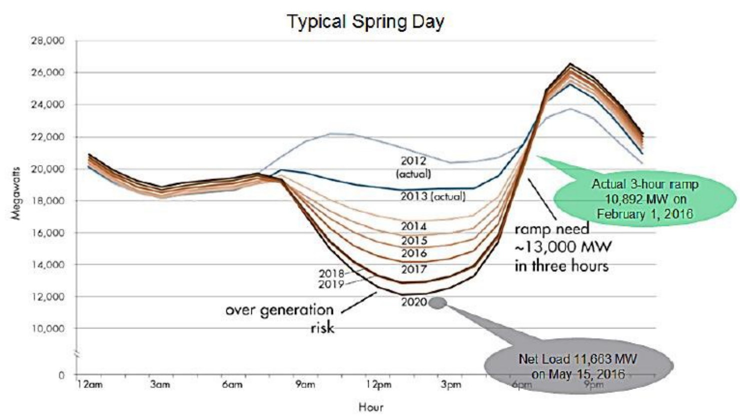

FIGURE 1: CALIFORNIA'S "DUCK CURVE"

- California is a leader in the movement toward a more distributed grid. Through policy initiatives like California Assembly Bill 327,[8] the state is reworking its regulatory framework to promote greater integration of distributed energy resources (including CHP), both to satisfy customer loads and to provide grid services. These initiatives will shift the electric grid away from an architecture that relies primarily on centralized generation plants and toward a design in which distribution-interconnected resources (including CHP units) could eventually participate in electricity markets and be assigned greater value for their proximity to customer load.

While this report focuses on California, other states are experiencing a similar evolution in their electric grids. In particular, generation from variable renewable sources is increasing across the United States, especially in regions like ERCOT. As shown in Figure 2, renewable resources in the United States have grown

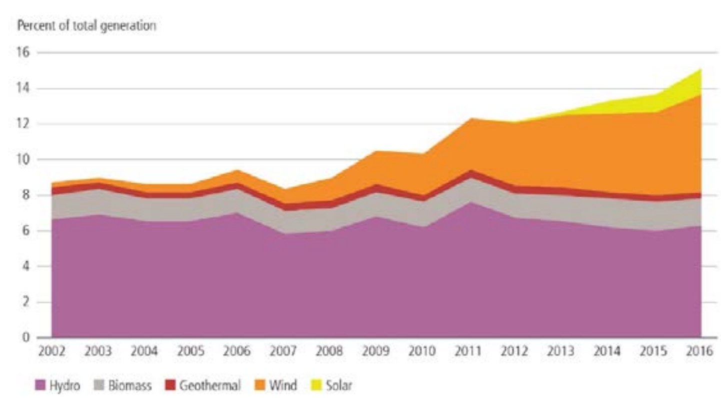

FIGURE 2: RENEWABLE GENERATION AS A PERCENTAGE OF TOTAL U.S. ELECTRICITY GENERATION

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[5] U.S. Department of Energy, Energy Information Administration. *Electric Sales, Revenue, and Prices*. Feb. 19, 2015.

[6] For additional information on California's RPS, see: www.energy.ca.gov/portfolio/index.html

[7] California ISO. *Fast Facts: What the Duck Curve Tells Us About Managing a Green Grid.* 2016.

[8] More information on AB 327 and California's Distribution Resources Planning process is available at: www.cpuc.ca.gov/General.aspx?id=5071

steadily over the last decade, due mainly to increasing adoption of wind and, more recently, solar generation.[9] As other states adopt or consider similar policies toward renewables and electric grid reform, the lessons learned from California's electric grid will become increasingly relevant for the rest of the country. In the future, this analysis may be extended to other areas of the United States, particularly to regions such as Texas that offer a similar combination of increasing renewable deployment, changing market rules, and a sizable installed base of existing CHP units.

Approach for Modeling Additional CHP on the California Electric Grid

This study examines the operation of the California electric grid in 2024 with and without additional CHP deployed at industrial sites. To estimate the potential impacts of the new CHP units on the California system, a team from the National Renewable Energy Laboratory (NREL) first evaluated a Baseline Scenario using the PLEXOS production cost model. PLEXOS simulates electricity operations at the hourly level, including all generator operating parameters and transmission congestion. The Baseline Scenario was based on NREL's *California Low Carbon Grid Study,*[10] which includes 28% variable renewable generation and 33% total renewable generation, thus meeting California's intermediate RPS requirement.

NREL used PLEXOS to identify the operational strategy that provides energy and reserves at minimum cost over the course of a model year. Reserves are a key component of grid operations, particularly at higher penetrations of variable renewable energy. While four reserve products are in the CAISO market,[11] PLEXOS models two general types of reserves: contingency and regulation. Contingency reserves refer to the holding of generator capacity for use during generator or transmission outages. Regulation reserves are used to balance small differences between projections and actual demand (load), actual variable renewable generation, and actual generator dispatch.

After establishing the Baseline Scenario, the analysis examined two scenarios that include additional CHP deployment (see Table 1): a Traditional CHP Scenario and a Flexible CHP Scenario. To develop these scenarios, experts from Oak Ridge National Laboratory (ORNL) and Resource Dynamics Corporation (RDC) first examined optimal locations for deployment of new CHP systems in California. The team used ORNL's Industrial Geospatial Analysis Tool for Energy Evaluation (IGATE-E) to estimate electrical loads at more than 24,000 manufacturing sites within the state, then calibrated those loads using data from the California Energy Commission. RDC subsequently used its DIStributed Power Economic Rationale Selection (DISPERSE) model to estimate the economic potential for CHP systems at sites with more than 100 kW of electrical load. The cost of deploying and operating a CHP system was compared to the cost of purchasing electricity and generating heat onsite using natural gas.[12] To forecast electric rates in 2024, RDC reviewed proposed rate increases from California utilities and academic sources, then applied an annual escalation of 3.7% to existing tariffs.[13] For sites that showed promise for CHP, the surplus capacity

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[9] U.S. Department of Energy. *Staff Report on Electricity Markets and Reliability.* August 2017.

[10] G. Brinkman, J. Jorgenson, A. Ehlen, and J. H. Caldwell. *Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California*, NREL/TP-6A20-64884. January 2016.

[11] California Independent System Operator. *Business Practice Manual for Market Operations.* Feb. 2, 2017.

[12] Industrial retail natural gas rates for the Traditional and Flexible CHP Scenarios were obtained by adding $1/MMBTU to the utility gas prices used by NREL in the Baseline Scenario. Utility gas prices in the Baseline Scenario were obtained from G. Brinkman, J. Jorgenson, A. Ehlen, and J. H. Caldwell. *Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California*, NREL/TP-6A20-64884. January 2016.

[13] Forecasted annual increases in electricity prices for California range from 1.9-6.3% in J. Cook, A. Smidebush, and S. Gunda. *The Future of Electricity Prices in California: Understanding Market Drivers and Forecasting Prices To 2040*,

was then evaluated as a grid resource, using future zonal wholesale grid prices, as estimated by NREL. Sites were selected for new CHP deployment if the DISPERSE model indicated that they could achieve a simple payback of the CHP installation costs within six years. The payback calculations did not include capital cost reductions from the federal Business Energy Investment Tax Credit (ITC) or incentive payments from California's Self Generation Incentive Program (SGIP).

TABLE 1: KEY ASSUMPTIONS FOR MODELING SCENARIOS

	Baseline Scenario	Traditional CHP Scenario	Flexible CHP Scenario
Technology Pathway	Existing CHP units only, no new units assumed	Price/performance similar to current CHP, price escalated to 2024 ($3,121/kW for 600 kW unit installed, $1,980/kW for 3MW unit installed)	Advanced CHP technology with 20–25% lower cost than Traditional CHP and flexible operating capability ($2,475/kW for 600 kW unit installed, $1,482/kW for 3MW unit installed)
CHP Operating Paradigm	CHP mainly serves site loads, but also has limited ability to support the grid (up to 10% of capacity)	CHP mainly serves site loads, but also has limited ability to support the grid (up to 10% of capacity)	CHP serves site loads with 60% of capacity and supports the grid with remaining 40%
Grid Policies Paradigm	CHP faces challenges in providing grid support	CHP is encouraged to support the grid via access to wholesale markets for energy and reserves	CHP is encouraged to support the grid via access to wholesale markets for energy and reserves
Additional Sites	None	1,800	2,700
Additional Capacity	None	1,583 MW	3,200 MW

The Traditional CHP Scenario and Flexible Scenario are based on two distinct "technology pathways" that define how CHP technology will mature in the near future. In the Traditional CHP Scenario, the installed cost of future CHP units is assumed to remain similar to today's CHP technology, although future installed costs are escalated to account for inflation. Performance of CHP units in the Traditional CHP Scenario is assumed to be similar to that of current CHP systems, which operate at or near full capacity to serve local site loads. In this scenario, CHP units are sized to supply electricity at the facility where they are deployed but can use some limited amount of capacity (up to 10%) to provide grid services when they are needed.

In contrast, the Flexible CHP Scenario assumes significant technical advances in CHP technology, making CHP systems in 2024 cheaper and capable of operating more flexibly than today's units. Units in the Flexible CHP Scenario are assumed to have a 25% lower installed cost in 2024 than units in the Traditional CHP Scenario.[14] In addition, CHP units in the Flexible CHP Scenario are assumed to offer higher efficiency over a broader range of operating conditions and can also provide as much as 40% of their capacity for

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UC Davis Energy Efficiency Center, December 2013. In addition, LADWP projected its 2015-2020 rates for large commercial/industrial to increase at 3.7% per year (www.myladwp.com/2016_2020_rate_request).

[14] While the installed cost ($/MW) is lower for units in the Flexible CHP scenario, site owners must install larger CHP units to simultaneously satisfy site loads and provide grid services. However, the combination of lower installed costs and additional revenue from providing grid services in the Flexible scenario results in a fairly short average payback period for CHP of 4.14 years.

grid services. Figure 3 shows the type of performance that would be achieved by the Flexible CHP units, which offer a flatter efficiency curve and maintain high efficiency, even when the units are turned down below 50% of full load during periods of modest site electric demand.

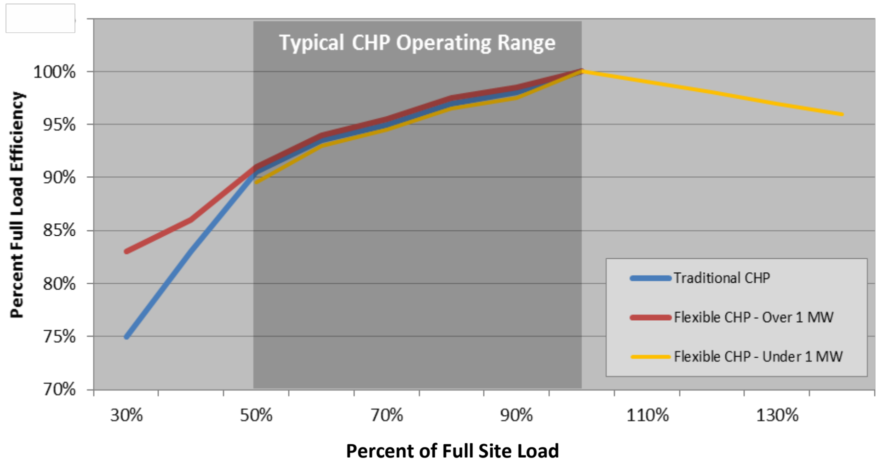

FIGURE 3: EFFICIENCY OF TRADITIONAL & FLEXIBLE CHP UNITS

In the Flexible CHP Scenario, the analysis assumes that large (>1MW) CHP units would typically operate between 60% and 70% of full load when serving site electric loads and would increase output up to 100% when simultaneously serving site loads and supplying grid services. In contrast, small (<1MW) CHP units (such as reciprocating engines equipped with inverters) are assumed to operate typically at up to 100% full load to serve site loads but might occasionally operate above rated capacity for short periods (less than 200 hours per year) to supply electricity to the electric grid when the need is greatest.[15] For all CHP units in the Flexible CHP Scenario, the analysis assumes that the additional thermal output generated during periods of increased electricity output to support the grid is not utilized on site. However, further investigation is needed to determine how much of this additional thermal energy could be used; if the additional thermal output were to be used on site (or stored for later use), CHP that operates in a flexible manner would be even more competitive in supporting the electric grid.[16]

Impacts of Flexible CHP on the California Grid

In the analysis, both the Traditional CHP and Flexible CHP Scenarios are compared to the Baseline Scenario, which includes only California's pre-existing CHP units. Currently, the state has 8,609 MW of CHP installed.[17] However, the Baseline Scenario conforms to NREL's *California Low Carbon Grid Study,* in which only 3,400 MW of existing California CHP units provide grid services (using up to 10% of their capacity), and the remaining units serve site loads, effectively reducing electricity demand from the grid at the sites where they reside. Therefore, the Baseline Scenario includes 3,400 MW of existing CHP units that are eligible to provide a total of 340 MW in grid services and assumes another 5,397 MW of existing CHP units continue operating to reduce customer loads at the sites where they are located (but are not visible to the grid operator).

[15] While some of today's inverter-based CHP systems are capable of temporarily increasing output, vendors generally discourage frequent use of this operating mode.

[16] This analysis also assumes that units in both the Traditional and Flexible CHP Scenarios operate in compliance with all applicable emissions regulations. However, a more detailed analysis of criteria pollutant emissions is needed to confirm this assumption under both scenarios.

[17] U.S. Department of Energy CHP Installation Database (as of Dec. 31, 2016). www.energy.gov/chp-installs

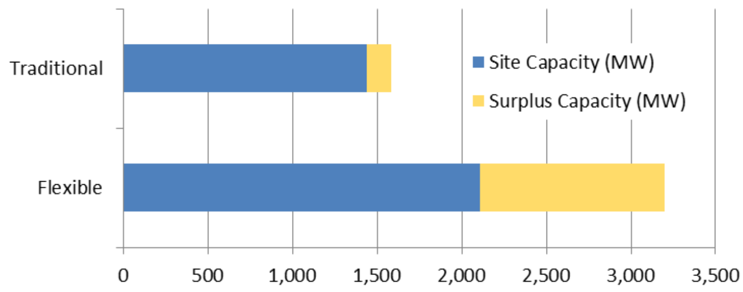

FIGURE 4: ADDITIONAL CAPACITY FROM NEW CHP UNITS

As shown in Figure 4, both non-baseline scenarios entail substantial additional capacity through the deployment of new CHP units. In the Traditional CHP Scenario, RDC analysis determined that 1,800 sites could economically deploy new CHP, yielding 1,435 MW of new CHP capacity to meet site loads and another 148 MW of surplus CHP capacity to support the grid.[18] In the Flexible CHP scenario, RDC concluded that 2,700 sites could economically deploy new CHP, resulting in 2,100 MW of baseload capacity (to meet site loads) and 1,100 MW of surplus CHP capacity available to support the California grid. This 2,100 MW[19] of new capacity to serve site loads is within the 3,309 MW limit of industrial site CHP technical potential previously identified by the California Energy Commission[20] and is more conservative than the California Air Resources Board's plan for future deployment of 4,000 MW of new CHP by 2020.[21] The generation capacity added in both non-baseline scenarios of the analysis is sizable relative to the state's existing generation fleet. In the Traditional CHP Scenario, the newly installed CHP units collectively represent 1.6% of California's installed capacity; in the Flexible CHP Scenario, new CHP accounts for 3.2%.

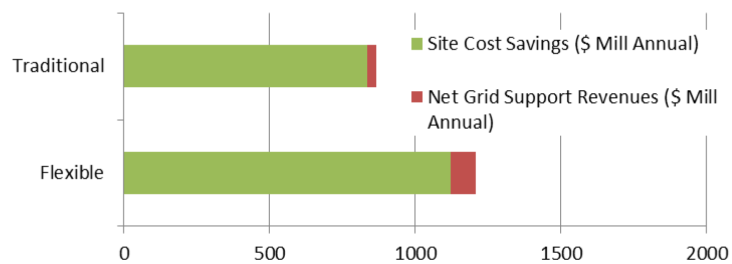

FIGURE 5: OWNERS' SAVINGS & REVENUES FROM NEW CHP

As outlined in Figure 5, deployment of new CHP systems in both non-baseline scenarios results in lower energy costs and increased revenue for industrial site owners in California. New CHP systems yield over $800 million in site energy cost savings in the Traditional CHP Scenario and also generate minor grid support revenues. In the Flexible CHP Scenario, financial benefits of new CHP systems include over $1.1 billion in site energy cost savings and $90 million in grid support revenues (net of generation costs). In the analysis, site energy cost savings resulted from avoided purchases of electricity at future retail industrial rates less the cost to operate and maintain the new CHP systems (including fuel). Grid support revenues result from the sale of grid services, including energy and reserves, into California's wholesale electricity market.[22] In both scenarios, CHP plays an important role in meeting the state's electricity demand. In the Traditional CHP

[18] The new capacity in the Traditional and Flexible CHP scenarios is in addition to the 3,400 MW of CHP capacity to serve site loads and the 340 MW of CHP capacity to provide grid services in the Baseline Scenario.

[19] The total nameplate capacity added in the Flexible CHP Scenario is 2,700 MW and includes 500 MW of temporary surge capacity that is made available for grid support. The total capacity of 3,200 MW is based on adding nameplate and surge capacities.

[20] For more information on the technical potential of CHP in California, see: B. Hedman, E. Wong, K. Darrow, A. Hampson. *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment.* CEC200-2012-002, February 2012.

[21] For details on the role of CHP in meeting California's climate change goals, see: California Air Resources Board. *Climate Change Scoping Plan*, September 2008.

[22] It is assumed that CHP owners of all sizes can participate in CAISO energy and ancillary services markets, either directly or through a third-party aggregator.

Scenario, new CHP units provide 4.1% of all electricity consumed in the state, while in the Flexible CHP scenario, the figure rises to 6.3%.

Because the additional CHP units serve local site loads and are also "flexed" to provide energy to the grid, CHP in the Traditional and Flexible CHP scenarios replaces baseload and peaking assets. Specifically, CHP displaces natural gas combined cycle (NGCC) units and natural gas combustion turbine (NGCT) units and also reduces electricity imports into California. Figure 6 shows the changes in generation by region for each of these two scenarios.[23] Displacement of NGCC units is likely due to the baseload portion of the CHP units' operations, which provides electricity for site loads and reduces the total load on California's grid, such that fewer NGCC units are needed to provide system energy. NGCT units are more typically used for peaking, providing energy during times of high stress and rapid ramping, such as during the evening solar ramp. Displacement of these units is primarily caused by the flexible surplus capacity of the CHP units. As California moves to even higher penetration of variable renewables, maintaining grid stability will become increasingly challenging. Each afternoon, solar renewable generation departs from California's grid, and other generation resources need to be ready to serve the load. *Flexible CHP units are one tool that can help ensure that the grid remains less stressed and economically efficient, even as higher levels of variable renewables are added.*

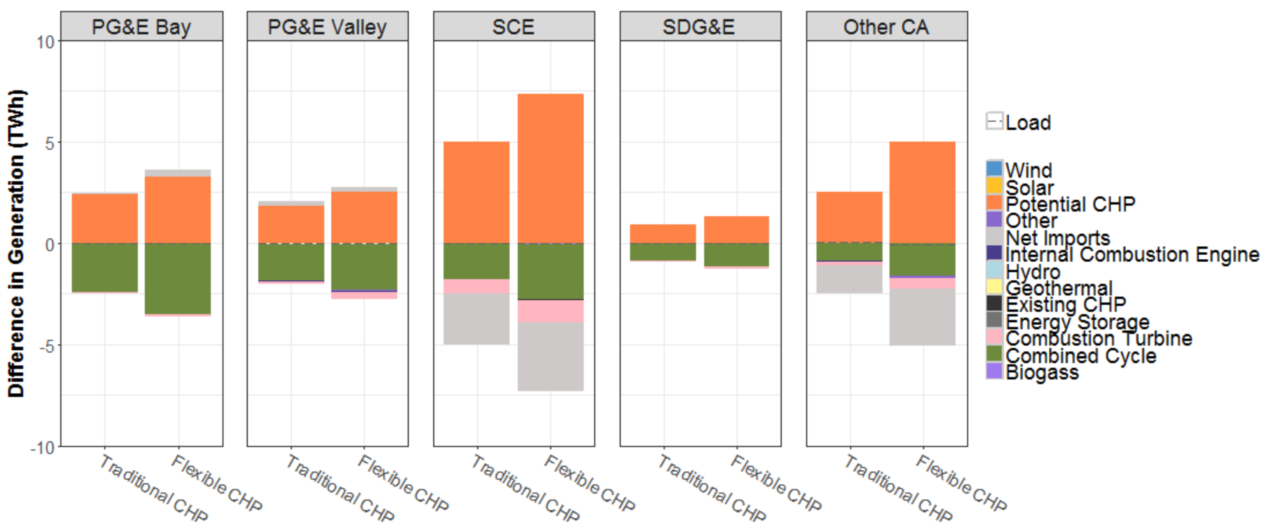

FIGURE 6: CHANGES IN GENERATION BY REGION RELATIVE TO THE BASELINE SCENARIO

The analysis also reveals that the additional CHP units may be particularly competitive in California's reserves markets; during the one-year simulation period, these units provided critical services (including regulation reserves and contingency reserves) to ensure stable operation of the state's electric grid. For example, in the Flexible CHP scenario, additional CHP units provided 39% of contingency reserves and 26% of regulation reserves across the state. Figure 7 outlines the differences from the Baseline Scenario for all types of generators providing reserves. In general, CHP displaces reserves provided by NGCC, NGCT, and "other" technologies (primarily demand response). The Flexible CHP scenario shows a much higher benefit to reserves than does the Traditional CHP scenario, due to the increased flexible capacity not required for meeting site needs. *This highlights a key advantage of CHP in providing grid support: because the*

[23] The five regions represent the service territories of California's large distribution utilities: Pacific Gas and Electric (PG&E) Bay Area, PG&E Central Valley, Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), and Other CA, which includes municipal utilities such as the Los Angeles Department of Water and Power (LADWP).

units generally operate continuously to serve site loads, they are ready to respond quickly with additional capacity when grid services are needed.

Reduced grid stress is another key impact of the new CHP units. In this analysis, "grid stress" is defined as hours in which certain constraints or limits are exceeded, such as overloading of transmission lines, failing to provide required reserves, or exceeding generator-rated properties. While violation of these constraints does not indicate that the grid is in danger of collapse, it does indicate that the system is sufficiently strained that reliability standards for operation cannot be met. Grid stress makes failures more likely, though not necessarily probable.

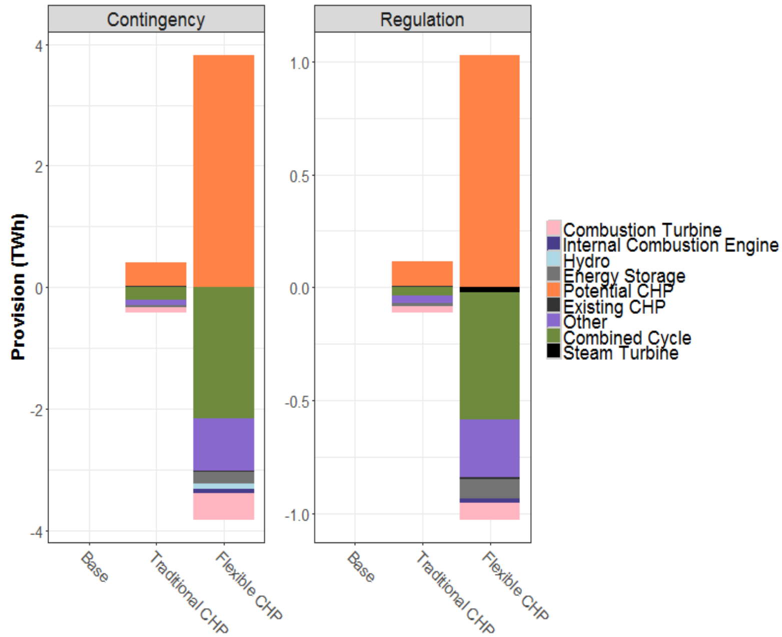

FIGURE 7: DIFFERENCE IN RESERVES PROVISION BY SCENARIO

In the Traditional CHP Scenario, new CHP units reduce the number of high-stress hours by approximately half in all studied regions. Improvements in the Flexible CHP Scenario are even more dramatic. For example, grid stress hours fall in the PG&E regions from 23 hours per year to 3 hours per year, and other regions experience similar reductions. Additionally, the Flexible CHP Scenario completely eliminates the hours in which there is a shortage of reserves. While the reserve shortages that occurred in the Baseline Scenario were small (representing less than 0.001% of the total required reserves), these results nonetheless demonstrate how flexible CHP systems can enable the grid to fully meet reliability requirements at all times.

Examining the amount of surplus capacity being utilized for each hour of the day and day of the year provides some insight into how the flexible CHP units help the grid. Figure 8 provides a heat map of CHP utilization in the Flexible CHP scenario. The top panel of Figure 8 shows smaller CHP systems, which were modeled as inverter-based units intended to use their flexibility for only a limited number of hours per year. The bottom panel shows larger CHP units, which meet site demands at part-load and have surplus capacity for grid operations.[24] As Figure 8 shows, CHP is used consistently during hours of high solar ramping, both in the morning and evening. Particularly as the amount of solar generation increases, the grid experiences periods of high stress. Increased utilization of CHP during these hours reduces the need to turn on additional generators to meet the rapidly changing net load patterns. In addition, California's need for electricity imports is also reduced, particularly at peak hours. Thus, California is less dependent upon other regions to provide the flexibility necessary to operate a grid with a high level of variable renewable generation.

[24] The larger CHP units offer higher efficiency and thus lower hourly cost to the grid.

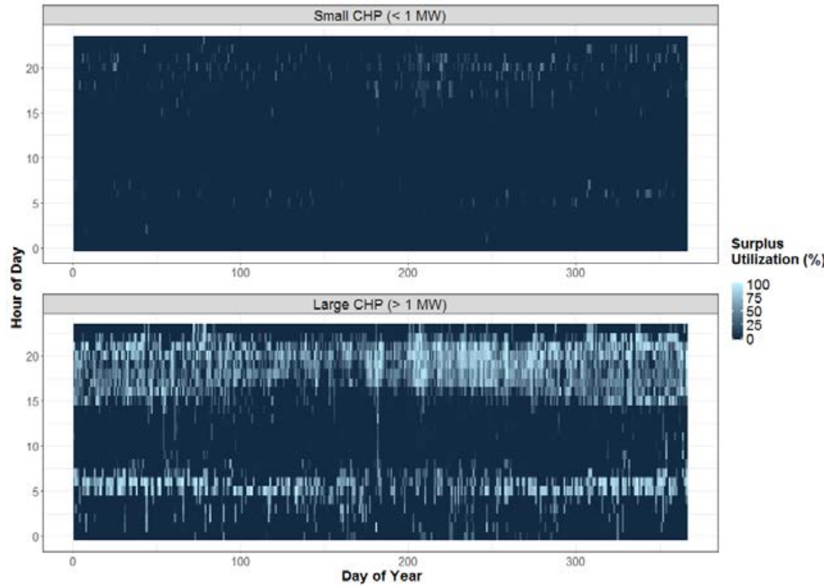

FIGURE 8: UTILIZATION OF FLEXIBLE CHP SURPLUS CAPACITY FOR ENERGY PROVISION

Adding CHP to California's generation fleet also modestly reduces the overall cost of meeting the state's electrical loads. As outlined in Table 2, the total cost to provide energy and reserves (including purchase of imports) is reduced by 1% in the Traditional CHP scenario and by 2% in the Flexible CHP scenario. While fuel costs and variable operations and maintenance (VO&M) costs increase, they are offset by the reduced need to purchase imported energy[25] from other states. In addition, reserve costs decrease because always-on CHP units are able to provide reserves inexpensively. In the Flexible CHP scenario, total system-wide benefits equal $265M annually. While the modeling effort does not quantify how all California stakeholders would be impacted by these savings, presumably lower system costs would translate into slightly lower electricity costs for all California energy consumers. It is also worth noting that Table 2 does not include industrial CHP owners' site energy cost savings, which total over $800M annually in the Traditional CHP scenario and over $1.2B annually in the Flexible CHP scenario.

TABLE 2: SUMMARY OF OPERATING COSTS TO MEET CALIFORNIA'S ANNUAL ELECTRICITY LOAD ($M/YEAR)

	Baseline Scenario	Traditional CHP Scenario	Flexible CHP Scenario
Emissions Cost	$ 2,393	$ 2,371	$ 2,364
Fuel Cost	$ 8,203	$ 8,369	$ 8,491
Start & Shutdown Cost	$ 263	$ 270	$ 264
VO&M Cost	$ 231	$ 307	$ 346
Subtotal: Operating Cost	$ 11,089	$ 11,318	$ 11,465
Reserve Cost	$ 139	$ 120	$ 72
Net Imports	$ 2,403	$ 2,062	$ 1,829
Total Cost	$ 13,631	$ 13,500	$13,366

[25] The cost of net electricity imports was calculated using methodology from G. Brinkman, J. Jorgenson, A. Ehlen, and J. H. Caldwell. *Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California*. NREL/TP-6A20- 64884, January 2016.

Additional Future Revenue Streams for Flexible CHP

While this study quantifies the value that new CHP systems would provide by selling energy and reserves to the California grid, future CHP systems may deliver other grid services, yielding additional revenue to their owners. Some of these services, such as voltage support, cannot be easily monetized under current market rules but could emerge in the future as potential revenue streams for flexible CHP units. Other services, such as capacity, can be monetized, although the precise value is unclear. In the case of capacity, deployment of additional CHP at California industrial sites would alleviate the need to construct new centralized power plants, a challenging and costly task in densely populated regions like Los Angeles. The North American Electric Reliability Corporation (NERC) requires a certain amount of excess capacity to guarantee grid reliability. In California, the state's Resource Adequacy (RA) program requires that load-serving entities procure sufficient capacity to meet future peak loads (plus reserve margin) through execution of bilateral forward commitment capacity contracts with generators. Other regions, such as the mid-Atlantic area served by PJM, have capacity markets in which new capacity is paid directly. A third model exists in Texas, where ERCOT allows very high energy prices at peak times to provide an incentive for adding new capacity.

This range of models for compensating new facilities for their capacity makes it difficult to determine the exact value of capacity to the California grid in any given year. However, an estimate can be developed by examining typical capacity payments in the United States and in California. Capacity payments in the United States range from $5/kW-yr to $100/kW-yr. In California, the 2016 weighted average price paid for forward capacity was $35.50/kW-yr, and 85% of bilateral capacity contracts were below $51/kW-yr.[26] Using a mean capacity value of $50/kW-yr (as applied in other studies[27]), CHP has an estimated capacity value of $79M per year in the Traditional CHP scenario, and $106M per year in the Flexible CHP scenario. Given the structure of California's RA program, at least a portion of these cost savings would be expected to accrue to California ratepayers, especially in the service territories of Southern California Edison and the Los Angeles Department of Water and Power (LADWP), where the majority of additional CHP units in the Flexible CHP Scenario would be deployed. Note that these two capacity value estimates are not included in the savings outlined in Table 2, and if even a portion of these values were accessible to California CHP owners, additional CHP deployment could be even more cost-effective at industrial sites in the state. Further, the capacity payments made to flexible resources (such as the units in the Flexible CHP Scenario) are likely to increase in the future as California places a higher value on flexible capacity through policy initiatives such as CAISO's Flexible Resource Adequacy Criteria and Must-Offer Obligation (FRAC-MOO) program.

Conclusion

This report outlines key ways in which additional CHP deployment in California could deliver critical benefits to the state's electric grid. In particular, if technological advances make CHP more affordable and capable of operating more flexibly, CHP would be economical to deploy at more industrial customer sites throughout California. The future grid could then not only rely on flexible CHP units to provide energy during periods when solar generation is dropping off; it also could use CHP systems as a source of valuable

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[26] L. Chow, S. Brant, J. Gannon, C. Sellden. *The 2015 Resource Adequacy Report.* California Public Utilities Commission, January 2017.

[27] For example, see M. Ruth, D. Cutler, F. Flores-Espino, G. Stark, T. Jenkin, T. Simpkins, J. Macknick. *The Economic Potential of Two Nuclear-Renewable Hybrid Energy Systems.* NREL/TP-6A50-66073, 2016.

reserve capacity. These CHP systems could displace natural gas combined cycle units (for baseload electricity), displace natural gas combustion turbine units (for peaking capacity), and reduce electricity imports into California.

This analysis also shows that flexible CHP units could generate over $1.2B in site energy cost savings for industrial owners in California, reduce California grid costs by up to $265M annually, and help the state's electric utilities avoid as much as $106M worth of capacity payments each year. In addition, deployment of flexible CHP generation could reduce the number of high-stress hours on the grid. Additional CHP units may also enhance grid resiliency by preserving uninterrupted operations during the failure of key generators or transmission lines. Further, by generating electricity closer to load centers, additional flexible CHP resources could decrease grid congestion. However, a detailed assessment of CHP's impact on grid resiliency and congestion was beyond the scope of this study. Further analysis is needed to understand CHP's future potential to enhance resilience and reduce grid congestion.