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COMBINED HEAT AND POWER MARKET ASSESSMENT

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Preface

The California Energy Commission's Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions. PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Energy-Related Transportation Research

Combined Heat and Power Market Assessment is the final report for the Combined Heat and Power Technical and Market Assessment project (Contract Number 500-06-011, Work Authorization number ICF-06-032-P-R) conducted by ICF International, Inc. The information from this project contributes to PIER's Environmentally Preferred Advanced Generation Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-654-4878.

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Abstract

This report analyzes the potential market penetration of combined heat and power systems in California from 2009 to 2029. This analysis evaluates the potential contribution of new combined heat and power to the reduction in emissions of greenhouse gases as required by the California Global Warming Solutions Act (Assembly Bill 32, Núñez, Chapter 488, Statutes of 2006) in 2006. The analysis characterizes the markets, applications, technologies, and economic competition for combined heat and power over the forecast period. A base case of future combined heat and power market penetration is developed that assumes a continuation of current trends and energy policies. The analysis then defines the market impacts of restoring the Self-Generation Incentive Program, providing payments to combined heat and power operators for carbon dioxide savings and providing a mechanism for the export of combined heat and power from systems larger than 20 megawatts that are not covered by current legislation to promote combined heat and power export.

Keywords: Public Interest Energy Research Program, PIER, combined heat and power, CHP, industrial market, commercial market, steam, gas turbine, reciprocating engine, fuel cell, microturbine, heat recovery, thermally activated cooling, greenhouse gases

Executive Summary

This report quantifies the long-term market penetration potential for combined heat and power and the degree to which combined heat and power can reduce potential greenhouse gas[1] emissions in support of the California Global Warming Solutions Act of 2006 (Assembly Bill 32, Núñez, Chapter 488, Statutes of 2006). The report also examines how implementing or restoring combined heat and power incentives would affect future combined heat and power market penetration. The analysis covered five task areas:

- Characteristics of existing combined heat and power in California
- Estimate of technical potential for combined heat and power in California
- Base case market analysis
- Market potential analysis under alternative scenarios
- Recommendations

This study represents an update of a similar analysis conducted, in part, by the same study team in 2004-2005.[2]

Characteristics of Existing CHP in California

Existing combined heat and power in California was characterized as part of this assessment to aid in both the identification of target markets for combined heat and power and the analysis of remaining technical potential. There are 8,829 megawatts (MW) of active combined heat and power in California at 1,183 sites. Just less than 90 percent of this capacity resides in large systems with site capacities of more than 20 MW. **Figure ES-1** shows the breakdown of existing combined heat and power by major market. The largest share of active combined heat and power capacity is located in the industrial sector. The second largest combined heat and power application is the provision of steam and power for enhanced oil recovery in the California heavy oil fields.

More than half of the total combined heat and power capacity is in the industrial sector and is heavily concentrated in five process industries: food processing, refineries, metals processing, pulp and paper, and chemicals. Combined heat and power in the commercial and institutional sector is spread through a larger number of individual applications, with the largest being college/universities, health care, government facilities, and utility-owned combined heat and power systems. While the commercial/institutional share is small compared to the total combined heat and power capacity in California at 19.5 percent, this market is comparatively well-developed compared to the national total for the commercial institutional sector of only 11 percent of total combined heat and power capacity.

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1 There are a number of gases classified as "greenhouse gases" including carbon dioxide, methane, and nitrous oxide. This analysis only considers the impact on carbon dioxide, the principal greenhouse gas produced from the deployment of combined heat and power.

2 *Assessment of CHP Market and Policy Options for Increased Penetration*, April 2005. EPRI, California Energy Commission 500-2005-060-D.

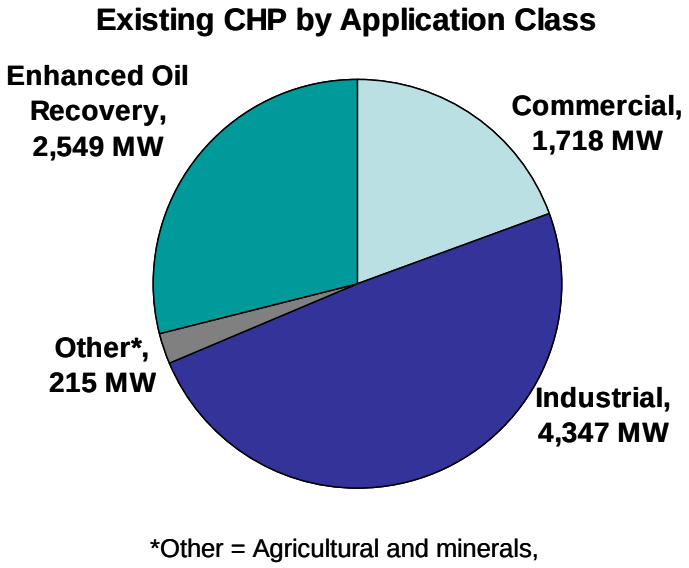

Figure ES-1: Existing Combined Heat and Power Capacity in California By Application Class

Source: ICF International, Inc. (ICF)

Estimate of Technical Potential for Combined Heat and Power in California

The study team analyzed a series of databases and energy load estimates for several thousand commercial, institutional, and industrial facilities to determine the technical potential for additional combined heat and power in California. The combined heat and power technical potential is an estimation of market size constrained only by technological limits – the ability of combined heat and power technologies to fit customer energy needs. Combined heat and power technical potential is calculated in terms of combined heat and power electrical capacity that could be installed at existing and new industrial and commercial facilities based on the estimated electric and thermal needs of the site.

Table ES-1 summarizes the technical potential for additional combined heat and power in the state by combined heat and power system size and market segment. The estimate includes both additional combined heat and power potential at existing businesses and combined heat and power potential from the expected growth in the new facilities over the next 20 years. High load factor markets represent industrial and commercial facilities such as hospitals and universities that operate around the clock, providing energy loads for combined heat and power systems to operate nearly continuously. Cooling markets and low load factor markets represent commercial and institutional market opportunities such as office buildings, schools, and laundries. The export market is composed solely of industrial and enhanced oil recovery sites that have large thermal loads. No combined heat and power export potential was assumed to come from commercial or institutional facilities. The total technical potential is more than 18,000 MW. Most of this potential is in industrial and commercial facilities that exist today; only a small portion is due to the growth in new businesses.

The *technical potential* for combined heat and power represents the target market from which *economic* CHP might be developed. These are the applications that are analyzed within the Combined Heat and Power Market Model using appropriate operating profiles, energy prices, and combined heat and power technology characteristics to determine the economic value of combined heat and power and the resulting market response.

Table ES-1: Existing Facility and New Technical Market Potential by Size and Market Segment

Market	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW	Total
Technical Potential at Existing Industrial and Commercial Facilities (MW)						
High Load Factor	1,152	624	1,522	1,042	245	4,584
Low Load Factor	111	10	5	15	0	141
High Load Factor Cooling	591	269	922	714	563	3,059
Low Load Factor Cooling	2,270	492	746	194	41	3,743
Export	71	110	261	571	3,530	4,544
Total	4,197	1,504	3,456	2,535	4,379	16,071
Technical Potential at New Industrial and Commercial Facilities (MW)						
High Load Factor	152	75	172	64	25	488
Low Load Factor	28	2	1	4	0	35
High Load Factor Cooling	164	70	243	151	112	740
Low Load Factor Cooling	458	119	172	30	6	786
Export	22	16	39	45	175	297
Total	823	283	628	294	317	2,346

Source: ICF International

Base Case Market Analysis

A Base Case market penetration was estimated based on current and expected economic conditions, regulatory policies, energy prices, and technology cost and performance characteristics.

Figure ES-2 shows the estimated market penetration by major component. The figure shows that the total combined heat and power market penetration for the Base Case is equal to nearly 3,000 MW. This total combined heat and power capacity is composed of three components: 2,731 MW for systems that provide power for on-site use, 304 MW for export of power under Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007), and 267 MW of avoided electric capacity represented by combined heat and power with thermally activated cooling. The on-site and export components of the total represent actual combined heat and power generating capacity. The avoided electric cooling capacity is central station capacity that would have otherwise been needed to supply the air conditioning now provided by the combined heat and power thermal recovery systems.

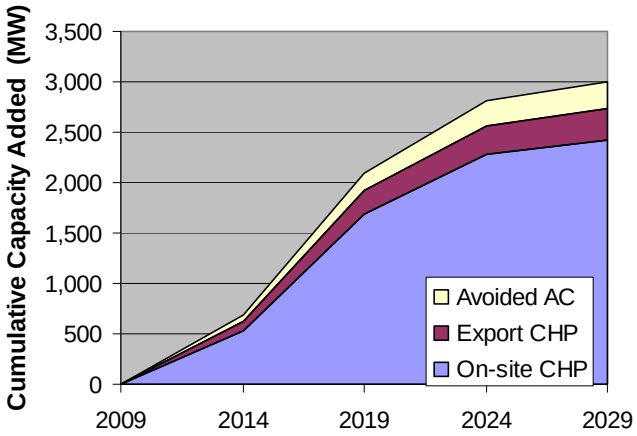

Figure ES-2: Base Case Cumulative Market Penetration by Market Type

Source: ICF Combined Heat and Power Market Model

Market Analysis Under Alternative Scenarios

The study team analyzed four combined heat and power incentive cases that reflect stimulus measures including restoration of the Self-Generation Incentive Program, payments to combined heat and power operators for carbon dioxide (CO_2) emissions reductions, expansion of combined heat and power export opportunities to systems larger than 20 MW, and, finally, a combination of all of these incentives.

Figure ES-3 shows the cumulative market penetration for the Base Case and the four incentive cases. The megawatt penetration values for each case include both combined heat and power generation and avoided air conditioning capacities. These cases can be summarized as follows:

- The CO_2 Payments Case assumes that combined heat and power operators receive $50/ton for avoided CO_2 emissions compared to the use of purchased power and fuel. The value chosen represents an average of yearly greenhouse gas adders defined by the California Public Utilities Commission for use in the calculation of payments for renewable electricity generation. This case produces a 244 MW increase in total market penetration over the Base Case.
- The Restore Self-Generation Incentive Program Case assumes that Self-Generation Incentive Program incentives are restored to fossil-fueled combined heat and power for a period of 10 years. Bringing back Self-Generation Incentive Program incentives would increase total market penetration by 497 MW over the Base Case. All of this increase occurs in the first 10 years of the market forecast and in the combined heat and power sizes smaller than 5 MW.
- The AB 1613 combined heat and power feed-in tariffs, when they are finalized, will apply only to systems 20 MW or less. The Expanded Export Case assumes that a basic contract mechanism is put in place for the export of excess combined heat and power-produced power to the grid from facilities larger than 20 MW. This scenario adds 1,441 MW of cumulative market penetration over the Base Case, representing about 40 percent of the total technical potential for large export power.

- The "All-In" Case is based on an expanded export case that uses an aggressive export pricing mechanism unique to this scenario and includes restoration of the Self-Generation Incentive Program and CO_2 emissions reduction payments. This scenario adds 3,521 MW over the base case; 79 percent of this increase is in the export market, reflecting the aggressive export pricing for combined heat and power projects larger than 20 MW.

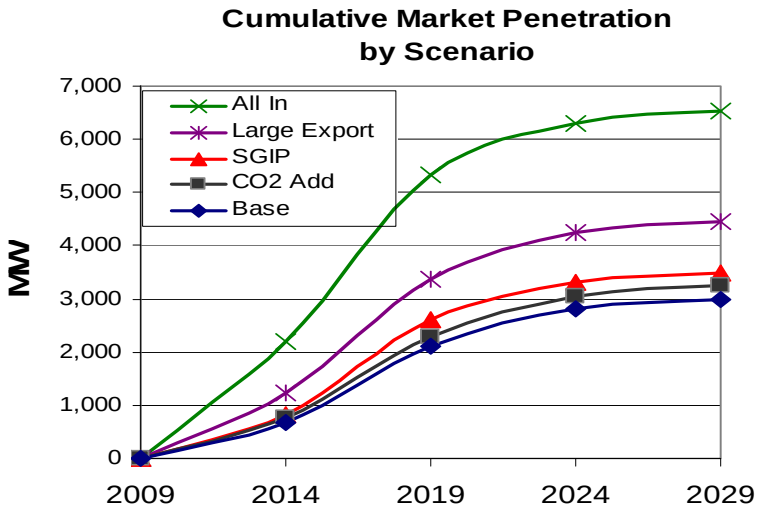

Figure ES-3: Base Case and Incentive Cases Cumulative Market Penetration Results

Source: ICF CHP Market Model

Table ES-2 shows the energy output characteristics of the cumulative combined heat and power market penetration by scenario.

- Total combined heat and power capacity by 2029 including avoided electric air conditioning capacity ranges from 2,988 MW in the Base Case to 6,515 MW in the "All-In" Case.
- This cumulative capacity will produce 18,991 to 45,779 million kilowatt-hour (kWh) per year by 2029.
- Natural gas for combined heat and power generation will require 188 trillion to 400 trillion Btu/year but will reduce boiler fuel consumption by 50 trillion to 143 trillion Btu/year. The deployment of combined heat and power results in overall energy savings of 37 trillion to 101 trillion Btu/year when fuel savings from displaced central station power is included.
- Average combined heat and power load factor ranges from 75.6 to 82.6 percent, and effective combined heat and power efficiencies range from 62 to 68 percent. The variation is due to the change in market shares for different types of combined heat and power by scenario.

- Energy savings will range from 39 trillion to 102 trillion Btu/year by the end of the forecast period.

Table ES-2: Scenario Comparison of Capacity, Outputs, Efficiency, and Load Factor

Scenario Characteristic	Base Case	CO_2 Payment	Restore SGIP	Expanded Export	"All-In"
Market Penetration (MW)	2,731	2,965	3,182	4,172	6,195
Avoided Electricity for Cooling (MW)	267	281	314	267	325
Total Capacity (MW)	2,998	3,246	3,496	4,439	6,519
CHP Fuel Consumption (billion Btu/year)	168,295	180,976	195,193	268,094	399,788
Avoided Boiler Fuel (billion Btu/year)	50,343	54,532	58,514	92,311	143,346
Electricity Generated (million kWh)	18,293	19,807	21,086	29,892	44,955
Avoided Electricity for Cooling (million kWh)	698	726	800	698	824
Total Electricity (million kWh)	18,991	20,533	21,887	30,590	45,779
Energy Savings (billion Btu/yr)	36,722	40,911	42,093	65,418	101,675
Average CHP Load Factor (percent)	76.5	76.2	75.6	81.8	82.8
Average Avoided Cooling Load Factor (percent)	29.8	29.5	29.1	29.8	29.0
Average Heat Rate, Btu/kWh	9,200	9,137	9,257	8,969	8,893
Effective CHP Efficiency (percent)	62.4	62.8	62.3	66.5	67.8

Source: ICF International

The market penetration and outputs for the five cases were evaluated with respect to their potential greenhouse gas emissions savings and compared to the California Air Resources Board (ARB) *Climate Change Scoping Plan* target of 4,000 MW of combined heat and power market penetration by 2020. **Table ES-3** shows the annual capacity, energy output, and greenhouse gas emissions savings for the ARB targets and for high and low penetration cases analyzed for this study. The ARB targets were based in part on the market penetration capacity forecast in a 2005 combined heat and power market assessment scenario that included export access for all combined heat and power system sizes and restoration of the Self-Generation Incentive Program. The assumptions in that 2005 scenario are similar to the "All-In" Case defined for this study. Comparing the "All-In" Case results for 2020 to the ARB targets shows that the ARB capacity and generation output targets for combined heat and power would be exceeded. The estimated CO_2 savings, however, are 10 percent lower than the ARB target. The reduced CO_2 emissions savings are the result of lower average annual load factors for CHP and lower average combined heat and power efficiencies than were used in the ARB analysis. The analysis showed that without further changes in combined heat and power regulation or policy (Base Case), the combined heat and power market penetration, generation output, and CO_2 savings will be considerably less than the ARB targets.

Table ES-3: Comparison of Study Results GHG Savings to ARB Target Estimate

Scenario	Capacity MW	Output GWh/year	Average Load Factor percent	Avoided CO_2 MMT/year	CO_2 Savings Rate lb/MWh
ARB 2020 Goal	4,000	30,000	85.6	6.70	492
Base Case 2020	2,240	14,486	73.8	1.93	294
Base Case 2029	2,998	18,293	69.6	2.67	322
"All In" Case 2020	5,532	39,545	81.6	6.05	337
"All In" Case 2029	6,519	45,779	80.2	7.20	347

Sources: ARB, ICF International

Recommendations and Conclusions

The development of policies to stimulate combined heat and power needs to address the needs of both large projects greater than 20 MW and small projects less than 20 MW. These two types of projects have differing characteristics and require different measures to stimulate additional market penetration. **Table ES-4** compares existing and estimated market penetration of large combined heat and power and small combined heat and power. Large combined heat and power represents 87 percent of the existing combined heat and power capacity. Under Base Case assumptions, however, only a very small amount of additional large combined heat and power is expected to penetrate the market, about 10 percent of the total additional capacity in the Base Case. In the "All-In" Case there is almost an even split between the capacity additions for large and small combined heat and power.

Table ES-4: Large vs. Small Combined Heat and Power Existing Market and Market Outlook (Generation Only, Avoided AC Not Included)

CHP Markets and Measures	Large CHP (>20 MW) MW	Small CHP (< 20 MW) MW
Existing QF Contracts	6,000	
Other Existing CHP	1,700	1,200
Total Existing	7,700	1,200
Market Penetration Base Case	278	2,453
Additional Market Penetration "All-In" Incentives	2,737	727
Total "All-In" Market Penetration	3,015	3,180

Source: ICF International

Small combined heat and power will respond to the restoration of the Self-Generation Incentive Program, the addition of CO_2 payments, and the finalization of the AB 1613 feed-in tariff. In addition, small combined heat and power can benefit from programs that reduce the capital and operating cost of these systems and also programs that increase awareness within the target markets of the cost and efficiency advantages of combined heat and power. In the large

markets, preservation of existing contracts will be an important factor followed by the development of an economically attractive mechanism for contracting for new projects. The analysis of technical potential showed that combined heat and power systems sized to the on-site thermal loads within large process industries will often produce far more power than can be used on site. Therefore, for these projects to move forward, the power must be exported to the grid at an economic price.

There are a number of measures that could help to remove barriers to combined heat and power market penetration:

- Education and training programs to address the lack of information or awareness and to reduce the perceptions of combined heat and power project risk.
- Demonstration of innovative technologies and applications to both reduce the cost of combined heat and power systems and to further increase awareness of combined heat and power capabilities in the target markets.
- Amelioration of combined heat and power project risk, both real and perceived, through the establishment of long-term contracts, gas contracting mechanisms that reduce the negative effects of gas price volatility, and improvement of combined heat and power technology cost and performance.
- Reduction of non-bypassable charges that combined heat and power must pay and encouragement of combined heat and power development through appropriate rate treatment.
- Development and implementation of incentives to internalize the social benefits of combined heat and power energy efficiency, greenhouse gas emissions reductions, transmission and distribution system support, peak capacity, and system reliability.

Greenhouse gas emissions reduction benefits of combined heat and power deployment and use depend not only on the characteristics of combined heat and power systems installed but also on the emissions of the central power being displaced. Further work should be done to determine the marginal sources of power during the next 20 years and the appropriate emissions values to use for avoided power purchases due to combined heat and power operation. These estimates should consider emissions savings differences for baseload combined heat and power, low load factor combined heat and power, and for avoided electric air conditioning. In addition to defining the marginal sources of power during different periods, further work should be undertaken to evaluate the expected line losses appropriate for different types and sizes of combined heat and power at different times of the year.

Combined heat and power thermal usage provides the added greenhouse gas emissions savings for combined heat and power compared to the separate purchase of fuel and power. There needs to be an established approach to measure and account for the thermal energy use from combined heat and power facilities. High thermal usage needs to be specifically encouraged. In this regard, higher efficiency absorption chillers or other thermally activated cooling technologies need to be developed and demonstrated to improve the greenhouse gas emissions performance of combined heat and power in applications with cooling.

1.0 Introduction

In early 2005 in support of the Integrated Energy Policy Report (IEPR) development process, the Energy Commission sponsored a comprehensive report on the market outlook for combined heat and power (CHP).[3] The passage of the California Global Warming Solutions Act[4] (Assembly Bill 32, Núñez, Chapter 488, Statutes of 2006) (AB 32) in 2006 has created renewed interest in energy-efficient technologies such as CHP and a need for a more up-to-date evaluation of CHP market opportunities and drivers in the current energy and economic climate.

The focus of this report is to quantify the long-term market penetration for CHP, using a revised and expanded version of the CHP market model developed for the 2005 study, and to show how CHP market penetration could be affected by implementing or restoring CHP incentives and by possible changes in exogenous market conditions.

This report is part of a larger project whose objective is to provide information in support of California Energy Commission energy policy planning. Specific project objectives include:

- Develop and update the inventory of combined heat and power (CHP) and combined cooling, heating, and power (CCHP) capacity in the state.
- Evaluate the effects of changes in California business activities, policies, and natural gas and retail electric rates since 2005 on CHP market potential.
- Develop new estimates of the technical and economic market potential for CHP and CCHP and provide an updated analysis of various incentive options to promote the development of the CHP and CCHP market opportunity.

The report analysis consists of five tasks:

- Characterize existing CHP in California.
- Develop an estimate of technical potential for CHP in California.
- Conduct a Base Case market analysis.
- Conduct market potential analyses under alternative scenarios.
- Make suggestions for clarifying analyses and additional scenarios.

This report provides the final results of these tasks.

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3 *Assessment of CHP Market and Policy Options for Increased Penetration*, EPRI, CEC-500-2005-060-D, April 2005.

4 AB 32 requires the California Air Resources Board (ARB) to develop regulations and market mechanisms that will ultimately reduce California's greenhouse gas (GHG) emissions by 25 percent by 2020. Mandatory caps will begin in 2012 for significant sources and ratchet down to meet the 2020 goals. There are a number of gases classified as "greenhouse gases" including CO_2, methane and Nitrogen Oxide (N_2O). This analysis only considers the impact on CO_2 emissions, the principal GHG that is reduced from the deployment of CHP. The terms GHG and CO_2 emissions will be used interchangeably in this report.

2.0 Project Approach

The CHP market assessment presented in this report is based on the ICF International, Inc. (ICF) CHP Market Model that estimates cumulative CHP market penetration as a function of competing CHP system specifications, current and future energy prices, and electric and thermal load characteristics for target markets. The CHP analysis includes the following four steps:

- Estimate of CHP Technical Market Potential – An estimate of the technically suitable CHP applications by size and by industry. This estimate is derived from the screening of customer data based on application and size characteristics that are used to estimate groups of facilities with appropriate electric and thermal load characteristics conducive to CHP.
- Estimate CHP Technology Cost and Performance – For each market size range, a set of applicable CHP technologies is selected for evaluation. These technologies are characterized in terms of their capital cost, heat rate, non-fuel operating and maintenance costs, and available thermal energy for process use on-site.
- Estimate of Energy Price Projections – Present and future fuel and electricity prices are estimated to provide inputs into the CHP net cost calculation.
- Estimate Market Penetration – Within each market size, the competition among applicable CHP technologies is evaluated. Based on this competition, the economic market potential is estimated and shared among competing CHP technologies. The rate of market penetration by technology is then estimated using a market diffusion model.

The project team analyzed and compiled a variety of information and data that was used in the ICF CHP Market Model to determine the future market penetration of CHP under a variety of input assumptions. The analysis is described in the following sections:

- Analysis of existing CHP in California.
- Evaluation of CHP cost and performance by technology and application size.
- Determination of current and future gas and electric prices.
- Evaluation of CHP technical potential from data on customer characteristics.
- Economic analysis of CHP by size and market and estimation of market penetration using the ICF CHP Market Model.

2.1. Existing CHP in California

The project team estimates that there are 8,829 MW of operating CHP in California at 1,183 sites. Just under 90 percent (%) of this capacity resides in large systems with site capacities greater than 20 MW.

The existing CHP was characterized as part of this assessment to aid in both the identification of target markets for CHP and for the technical potential analysis. Most importantly from an analytical perspective, this assessment seeks to identify remaining CHP potential in California.

Therefore, the existing stock of active CHP installations has been subtracted from the technical market potential used in this assessment.

As shown in **Figure 1**, the largest share of active CHP capacity is located in the industrial sector, with the largest single application being the provision of steam in oil fields for enhanced oil recovery (EOR). The figure below shows a breakdown of the existing CHP capacity in California by application class.

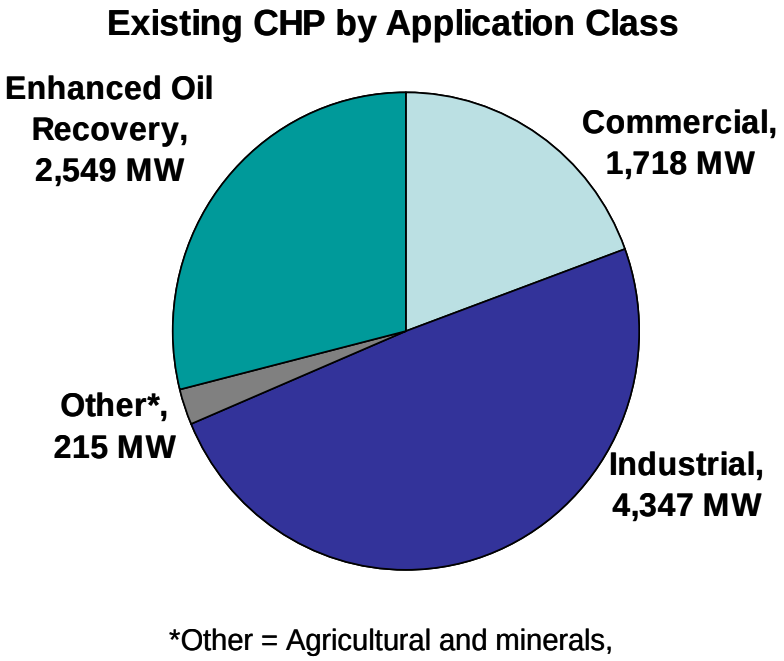

Figure 1: Existing CHP Capacity in California by Application Class

Source: ICF CHP Installation Database

Figure 2 shows that more than half of the total capacity is in the industrial sector and is heavily concentrated in five process industries: food processing, refineries, metals processing, pulp and paper, and chemicals. The commercial and institutional sector is spread through a larger number of individual market applications, with the largest being college/universities, health care, and government facilities. While the commercial/institutional share is small compared to the total CHP capacity in California at 19.5%, this market is comparatively well-developed compared to the rest of the country; the commercial/institutional sector represents only 11% of total CHP capacity on a national basis. **Figure 3** shows the breakdown of CHP in the commercial/institutional sector.

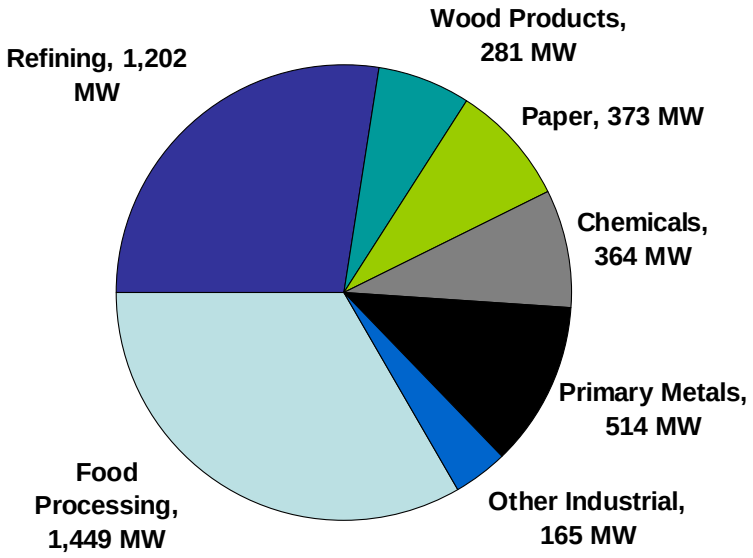

Figure 2: Industrial CHP Capacity in California

Source: ICF CHP Installation Database

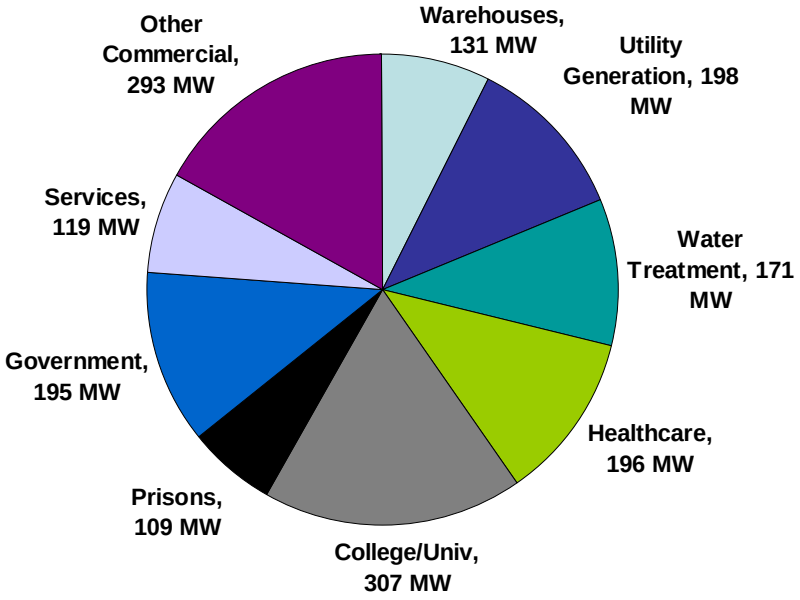

Figure 3: Commercial CHP Capacity in California

Source: ICF CHP Installation Database

The geographic location of CHP systems in California is spread out through all major utility territories. Pacific Gas and Electric (PG&E) has the largest share of CHP capacity in its service area due to the concentration of large oil fields and refineries in its territory. **Figure 4** shows the distribution of CHP by utility service area. This breakdown depicts the actual physical location

of the CHP system and does not account for systems located in one utility territory that sell electricity to other utilities or parties outside the territory. One area of the state that is known to have this issue is Kern County, where a significant amount CHP capacity is installed at enhanced oil recovery facilities that are geographically within Pacific Gas and Electric's service territory but export electricity to Southern California Edison (SCE).

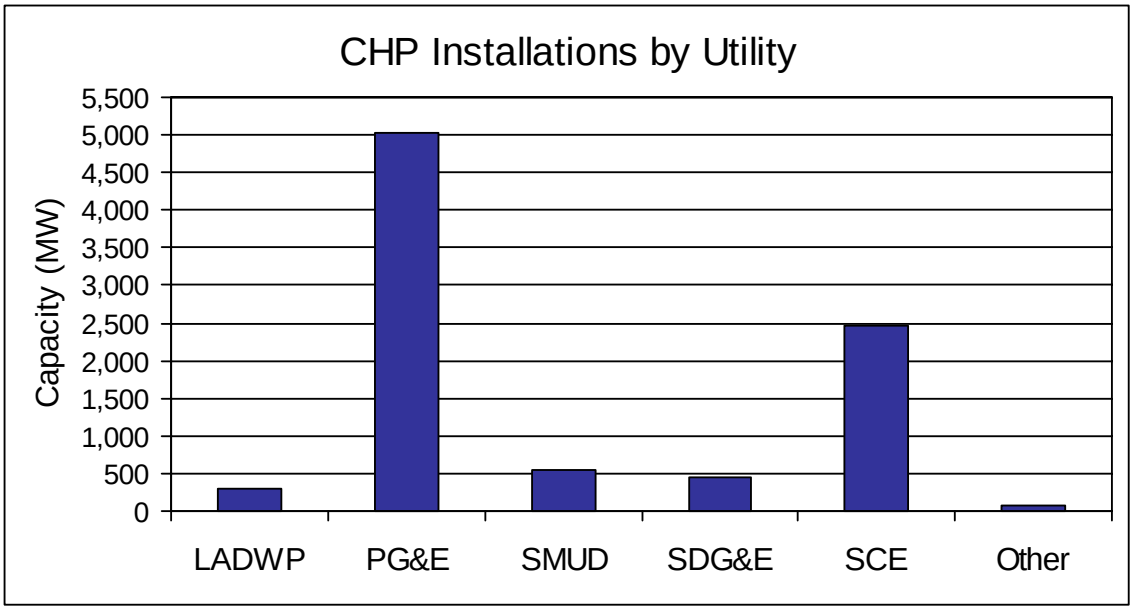

Figure 4: Installed CHP in California by Utility Service Area

Source: CHP Installation Database

The existing CHP installations can also be characterized in terms of the size of the facility (
Figure 6: Existing CHP in California by Fuel

), the primary fuel utilized (Error! Reference source not found.), and the type of prime mover (**Figure 7**).

- Large installations make up most of the existing capacity. Systems smaller than 5 MW represent only 5.5% of total existing CHP capacity in California. Systems larger than 100 MW represent almost 40% of the total existing capacity. However, as will be shown later, the market saturation of CHP in large facilities is much higher than for smaller sites. Much of the remaining technical market potential is composed of smaller systems.
- By far the most important fuel utilized for CHP is natural gas, which represents 84% of the total installed capacity. There are 12 coal-fired CHP plants, making up 4.5% of capacity, and 5 oil-fired plants, making up less than one-tenth of 1% of capacity. Renewable fuel makes up 4.5% of the total capacity with the bulk of this capacity in the wood products, paper, and food processing industries and in wastewater treatment facilities.
- Given the concentration of large scale systems in the existing CHP population, the most common prime movers are gas turbines. In the very large sizes, these are often in a

combined-cycle configuration. In intermediate sizes, simple-cycle gas turbines are used. Renewable fuels or waste fuels are used in boilers that drive steam turbines in the wood, paper, food and petrochemical industries. Most of the small systems are driven by gas-fired reciprocating engines; while total capacity is small (5%), the reciprocating engine technology represents the greatest number of CHP sites (62%). Emerging technologies, such as microturbines and fuel cells, make up a small but growing fraction of systems.

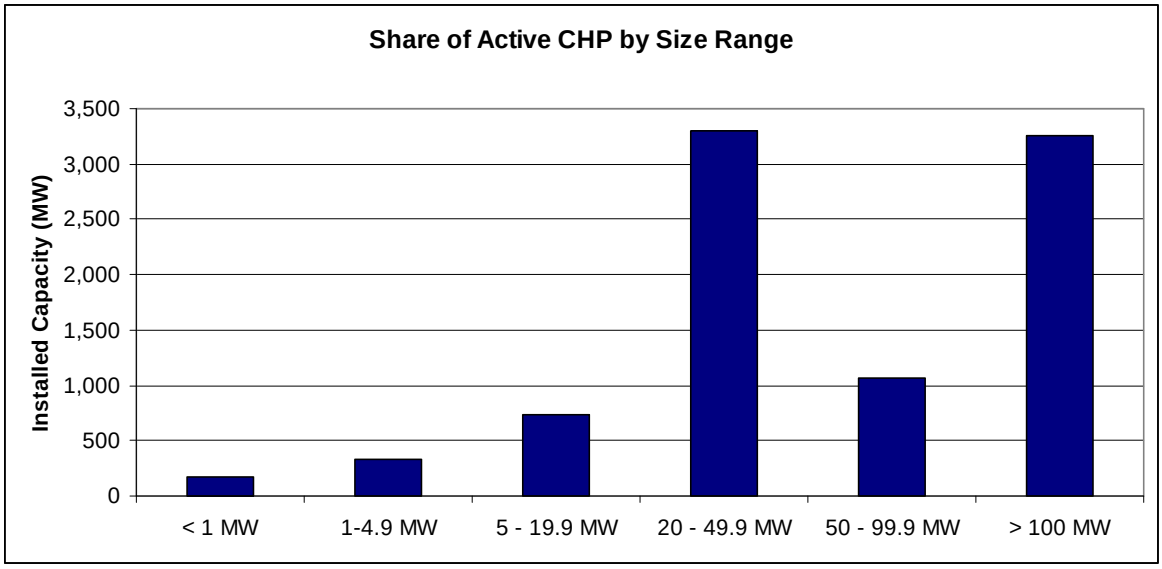

Figure 5: Existing CHP in California by Size Range

Source: ICF CHP Installation Database

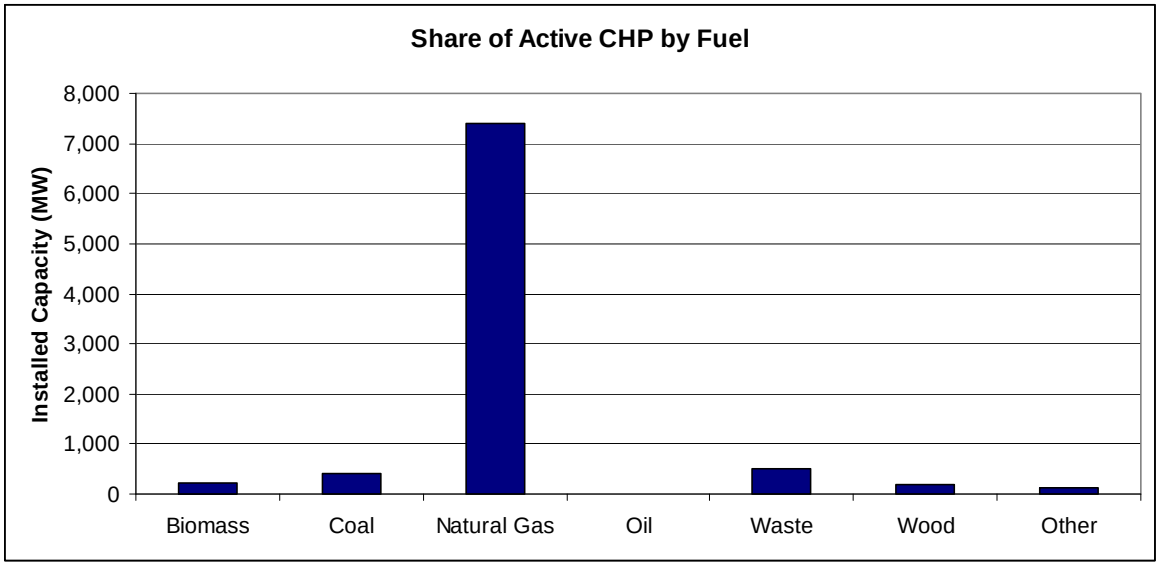

Figure 6: Existing CHP in California by Fuel

Source: ICF CHP Installation Database

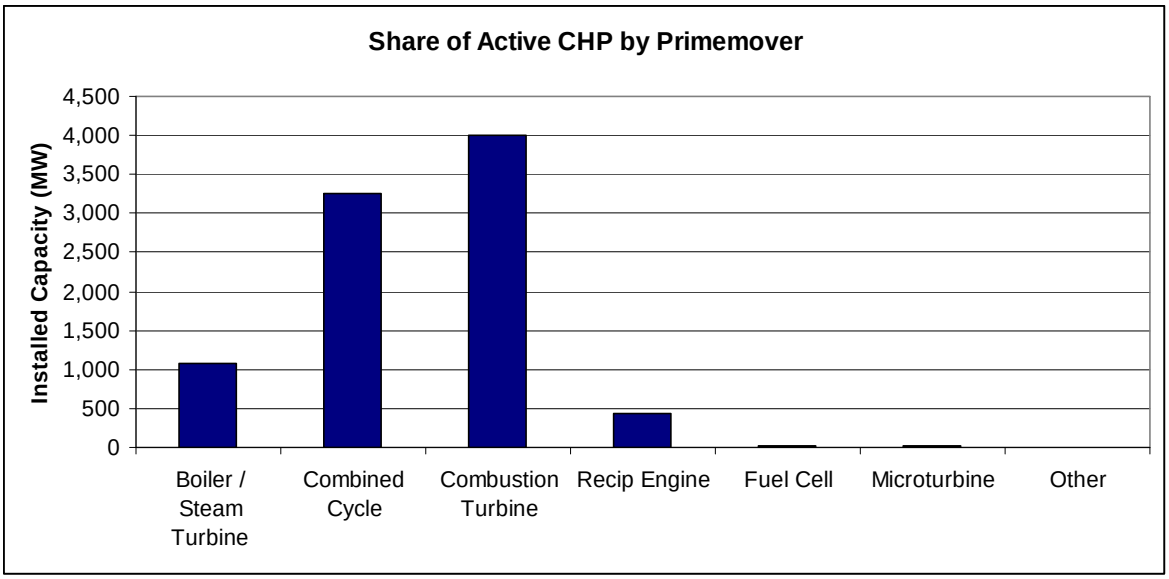

Figure 7: Existing CHP in California by Prime Mover

Source: ICF CHP Installation Database

The installation of CHP systems in California has not been consistent over time. There have been periods of time when CHP market activity has been higher than other periods, typically caused by regulatory and legislative changes. In 1978 Congress passed the Public Utilities Regulatory Policies Act (PURPA) to promote energy efficiency. PURPA encouraged energy-efficient CHP and power production from renewables by requiring electric utilities to interconnect with "qualifying facilities" (QFs). CHP facilities had to meet minimum fuel-specific efficiency standards to become a QF. PURPA required utilities to provide QFs with reasonable standby and backup charges, and most importantly to purchase excess electricity from them at the utilities' avoided costs. PURPA also exempted QFs from regulatory oversight under the Public Utilities Holding Company Act and from constraints on natural gas use imposed by the Fuel Use Act.

PURPA was enacted at the same time that larger, more efficient, lower cost combustion turbines and combined cycle systems became widely available. These technologies were capable of producing more power in proportion to useful thermal output compared to traditional boiler/steam turbine CHP systems. Therefore, the power purchase provisions of PURPA, combined with the availability of these new technologies, resulted in the development of very large merchant power plants designed for high electricity production.

The environment changed again in the mid-1990s with the advent of deregulated wholesale markets for electricity. Independent power producers could now sell directly to the market without the need for QF status, and CHP development slowed (**Figure 8**). The result was more restricted access to power markets, and users began delaying purchase decisions with an expectation of low electric prices in the future as many states began to restructure their individual power industries. By the end of the 1990s, policy makers began to explore the efficiency and emission reduction benefits of thermally based CHP. They realized that a new

generation of locally deployed CHP systems could play an important role in meeting national energy needs in a less carbon-intensive manner. As a result, the federal government and several states began to promote deployment of CHP. CHP has been singled out for support by the U.S. Department of Energy (DOE) and U.S. Environmental Protection Agency (EPA), which committed to a target of increasing CHP capacity to 92 GW between 2000 and 2010. The following figure shows how the installation of CHP capacity in California followed the changing market.

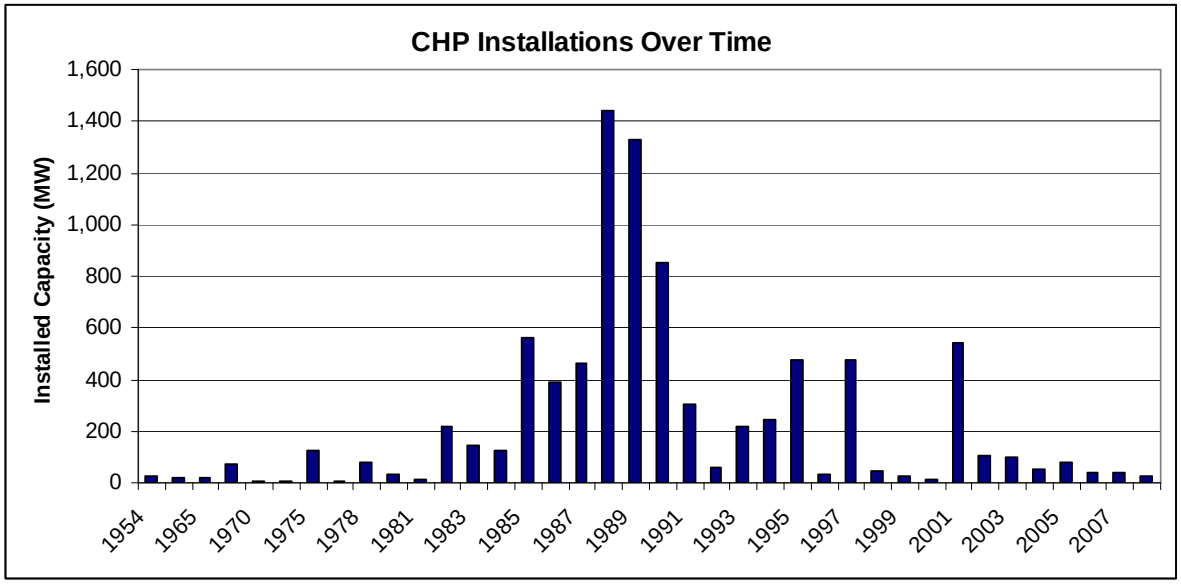

Figure 8: Existing CHP Installations in California by Year Installed

Source: ICF CHP Installations Database

California's Self-Generation Incentive Program (SGIP) has been a recent driver of small CHP system installations. The SGIP provides incentives to support emerging distributed energy resources, which included CHP from 2001 through 2007, on the customer's side of the utility meter. The SGIP program is responsible for more than 1,270 projects being installed, providing over 330 MW in capacity. It is estimated that CHP projects make up almost 200 MW of the total capacity additions from the program. Since SGIP projects are in the small size range, they tend to be in mostly commercial or small industrial applications.

Additional detailed tables of existing CHP installations in California are available in **Appendix A**.

2.2. CHP Technology Characterization

The CHP system itself is the engine that drives the economic savings. The cost and performance characteristics of CHP systems determine the economics of meeting the site's electric and thermal loads. Most notable technology options available today for CHP include industrial and aero-derivative gas turbines, reciprocating engines, microturbines, and fuel cells. The primary fuel option in California for these technologies is natural gas because of its availability, cost and emission qualities. Other fuel sources include landfill gas, digester gas, industrial waste fuel

streams, propane, and diesel fuel. However, diesel fuel and propane can be prohibitively expensive for CHP. Furthermore, diesel engine generation sets can rarely be permitted in California as a prime power or as part of a CHP project. Landfill and digester gas, in sufficient quantities, are generally economical with or without heat recovery (CHP).

Gas turbines and combined-cycle units (gas turbines incorporating a steam turbine bottoming cycle) account for a majority of the inventory of operating CHP in the United States while reciprocating engines dominate the number of installations. The competitive size span for the various CHP technology classes is depicted in **Figure 9**. Also noted are the market dominant technologies by size class.

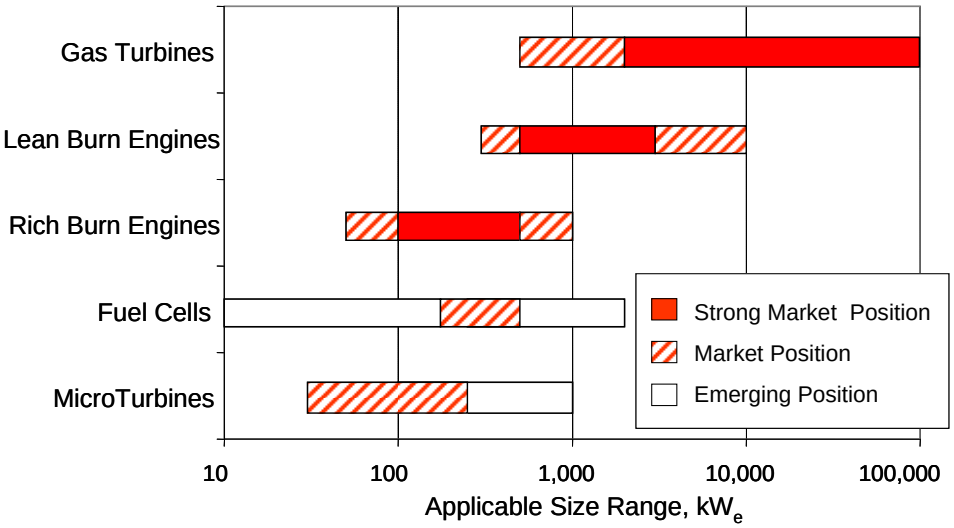

Figure 9: Technology Size Coverage

Source: Oak Ridge National Laboratory[5]

Each of these technologies is summarized below with emphasis placed on systems capable of being deployed in California.

A representative sample of commercially and emerging CHP systems was selected to profile performance and cost characteristics in CHP applications. The selected systems range in capacity from approximately 100 to 40,000 kW. The technologies include gas-fired reciprocating engines, gas turbines, microturbines, and fuel cells. The appropriate technologies were allowed to compete for market share in the penetration model. In the smaller market sizes, reciprocating engines competed with microturbines and fuel cells. In intermediate sizes (1 to 20 MW), reciprocating engines competed with gas turbines.

Cost and performance estimates for the CHP systems were based on work undertaken for the EPA.[6] The foundation for these updates is based on work previously conducted for NYSERDA[7],

5 *Clean Distributed Generation Performance and Cost Analysis*, DE Solutions for ORNL. April 2004.
6 *CHP Technology Characterization*, EPA CHP Partnership Program, December 2007.
7 *Combined Heat and Power Potential for New York State*, Energy Nexus Group (later became part of EEA), for NYSERDA, May 2002.

on peer-reviewed technology characterizations that Energy and Environmental Analysis (EEA) developed for the National Renewable Energy Laboratory[8] and on follow-up work conducted by DE Solutions for Oak Ridge National Laboratory.[9] Additional emissions characteristics and cost and performance estimates for emissions control technologies were based on work ICF conducted for EPRI.[10] Data are presented for a range of sizes that include basic electrical performance characteristics, CHP performance characteristics (power to heat ratio), equipment cost estimates, maintenance cost estimates, emission profiles with and without after-treatment control, and emissions control cost estimates. The technology characteristics are presented for three years: 2009, 2014, and 2019. The 2009 estimates are based on current commercially available technologies. The cost and performance estimates for 2014 and 2019 reflect current technology development paths and currently planned government and industry funding. These projections were based on estimates included in the references listed above. NO_x emissions estimates in lb/MWh are presented for each technology both with and without after-treatment control (AT). For this analysis, all technologies were required to meet a NO_x emissions requirement of 0.07 lb/MWh including a CHP thermal credit. After-treatment costs were included in the technology model if after-treatment was needed to meet this required emission level.

2.2.1. Reciprocating Engines

Natural gas-fueled reciprocating engines (engines) offer low first cost, easy start-up, proven reliability when properly maintained, and good load-following characteristics. Engines are well suited for packaged CHP in commercial and light industrial applications that require less than 5 MW. Natural gas engines for power generation currently rely on spark ignition (SI) to combust the fuel. Historically, there have been two types of SI engines: rich-burn and lean-burn.

Rich-burn engines operate near stoichiometric combustion conditions as do automotive engines. Detonation constraints limit the electric efficiency of rich burn engines to the 28-30% (HHV) range. Rich burn engines emit high levels of oxides of nitrogen (NO_x) that are readily treated with passive three-way catalysts similar to that used in automobiles. With a properly sized and controlled system, these catalysts can achieve emission reductions greater than 99% and can meet the ARB 2007 NO_x guidelines.

Lean-burn engines are inherently more efficient, more powerful, less maintenance intensive, and produce considerably fewer *engine-out* pollutants than rich-burn engines.[11] However, in order to meet current emission requirements in stringent environmental regions such as California, a relatively expensive selective catalytic reduction (SCR) system and oxidation

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8 *Gas-Fired Distributed Energy Resource Technology Characterizations,* NREL, November 2003, http://www.osti.gov/bridge.

9 *Clean Distributed Generation Performance and Cost Analysis*, DE Solutions for ORNL. April 2004.

10 *Assessment of Emerging Low-Emissions Technologies for Distributed Resource Generators*, EPRI, January 2005.

11 Engine Manufacturers Association, *Gaseous-Fueled Reciprocating Engines and the Distributed Energy Market,* June 2003.

catalyst is required. Advanced SCR systems can remove greater than 95% of NO_x emissions allowing lean burn engines to meet the ARB 2007 requirements with the CHP thermal credit.

The schematic in **Figure 10** illustrates a reciprocating engine equipped with heat recovery.

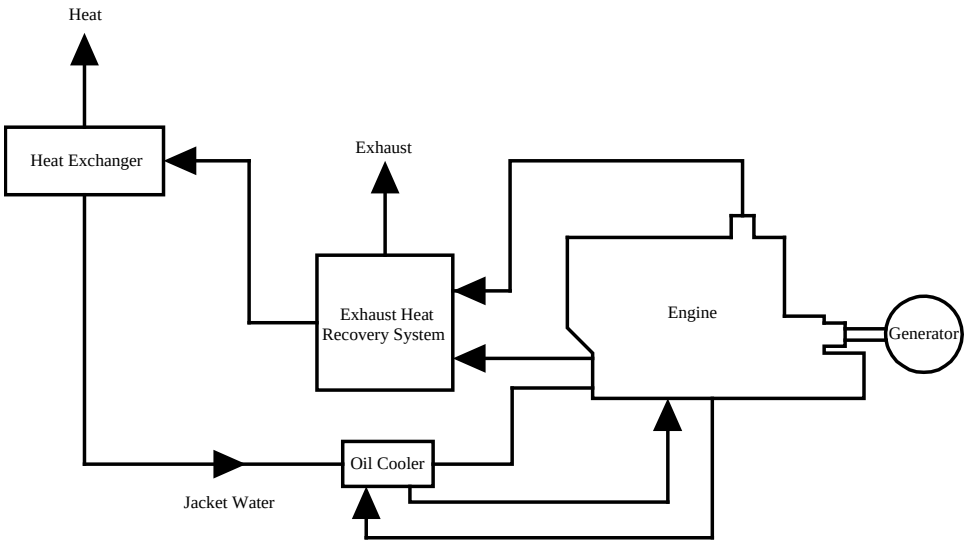


Figure 10: Reciprocating Engine CHP System

Source: DE Solutions

In reciprocating engines, the recovered heat is typically split between the exhaust at temperatures between 900°F and 1,000°F, and the jacket coolant, which is usually kept below 220°F. Heat is also available in some engines from the lube oil cooler. Engines can provide most of the available heat at hot water temperatures between 215°F and 230°F, or they can provide high-grade steam using only the exhaust heat.

The reciprocating engine cost and performance assumptions are shown in **Table 1** and **Table 2.**

Table 1: Reciprocating Engine Technology in the 50–500 kW Size Range

CHP System	Characteristic/Year Available	2009	2014	2019
100 kW-Rich Burn with 3 way catalyst	Installed Costs, $/kW	2,210	1,925	1,568
	CA Installed Costs	2,475	2,137	1,741
	Heat Rate, Btu/kWh	12,000	10,830	10,500
	Electric Efficiency, %	28.4	31.5	32.5
	Thermal Output, Btu/kWh	6100	5093	4874
	Overall Efficiency, %	79.3	78.5	78.9
	Power to Heat	0.56	0.67	0.70
	O&M Costs, $/kWh	0.02	0.016	0.012
	NO_x Emissions, lbs/MWh (w/ AT)	0.15	0.15	0.15
	NO_x Emissions, lbs/MWh (w/ AT) CHP Credit	0.05	0.06	0.06
	After-treatment Cost, $/kW	incl.	incl.	incl.

Source: ICF International

Table 2: Reciprocating Engine Technology in the 500 kW–5 MW Size Range

CHP System	Characteristic/Year Available	2009	2014	2019
800 kW-Lean Burn	Installed Costs, $/kW	1,640	1,443	1,246
	CA Installed Costs	1,820	1,602	1,384
	Heat Rate, Btu/kWh	9,760	9,750	9,225
	Electric Efficiency, %	35.0	35.0	37.0
	Thermal Output, Btu/kWh	4299	4300	3800
	Overall Efficiency, %	79.0	79.1	78.2
	Power to Heat	0.79	0.79	0.90
	O&M Costs, $/kWh	0.016	0.013	0.011
	NO_x Emissions, gm/bhp (w/o AT)	0.7	0.4	0.25
	NO_x Emissions, lbs/MWh (w/o AT)	2.17	1.24	0.775
	NO_x Emissions, lbs/MWh (w/ AT)	0.11	0.12	0.08
	NO_x Emissions, lbs/MWh (w/ AT) CHP Credit	0.05	0.05	0.04
	After-treatment Cost, $/kW	300	190	140
3000 kW-Lean Burn	Installed Costs, $/kW	1,130	1,100	1,041
	CA Installed Costs	1,254	1,221	1,155
	Heat Rate, Btu/kWh	9,492	8,750	8,325
	Electric Efficiency, %	35.9	39.0	41.0
	Thermal Output, Btu/kWh	3510	3189	2900
	Overall Efficiency, %	72.9	75.4	75.8
	Power to Heat	0.97	1.07	1.18
	O&M Costs, $/kWh	0.014	0.012	0.01
	NO_x Emissions, gm/bhp (w/o AT)	0.7	0.4	0.25
	NO_x Emissions, lbs/MWh (w/o AT)	2.17	1.24	0.775
	NO_x Emissions, lbs/MWh (w/ AT)	0.11	0.12	0.08
	NO_x Emissions, lbs/MWh (w/ AT) CHP Credit	0.05	0.06	0.04
	After-treatment Cost, $/kW	200	130	100
5000 kW-Lean Burn	Installed Costs, $/kW	1,130	1,099	1,038
	CA Installed Costs	1,254	1,220	1,153
	Heat Rate, Btu/kWh	8,758	8,325	7,935
	Electric Efficiency, %	39.0	41.0	43.0
	Thermal Output, Btu/kWh	3046	2797	2605
	Overall Efficiency, %	73.7	74.6	75.8
	Power to Heat	1.12	1.22	1.31
	O&M Costs, $/kWh	0.011	0.01	0.009
	NO_x Emissions, gm/bhp (w/o AT)	0.5	0.4	0.25
	NO_x Emissions, lbs/MWh (w/o AT)	1.55	1.24	0.775
	NO_x Emissions, lbs/MWh (w/ AT)	0.11	0.12	0.08
	NO_x Emissions, lbs/MWh (w/ AT) CHP Credit	0.06	0.07	0.04
	After-treatment Cost, $/kW	150	115	80

Source: ICF International

2.2.2. Natural Gas Turbines

Industrial gas turbines are an established technology used for a variety of on-site generation and mechanical drive applications. Gas turbines are most competitive in sizes larger than 3 MW in CHP applications. Gas turbines have moderate electric efficiencies and excel in applications with high heat requirements.

The most common CHP system is a simple cycle gas turbine CHP system illustrated in **Fugure 11**. Intake air is compressed and ducted into a fueled combustor increasing the temperature of the compressed air stream. The compressed air stream is then ducted into the turbine expander, which creates power to drive the compressor and produce electricity. All of the rejected heat is in the exhaust at temperatures in the range of 900°F to 1,000°F, which can be used in a variety of applications including high-temperature steam industrial processes and double-effect absorption cooling.

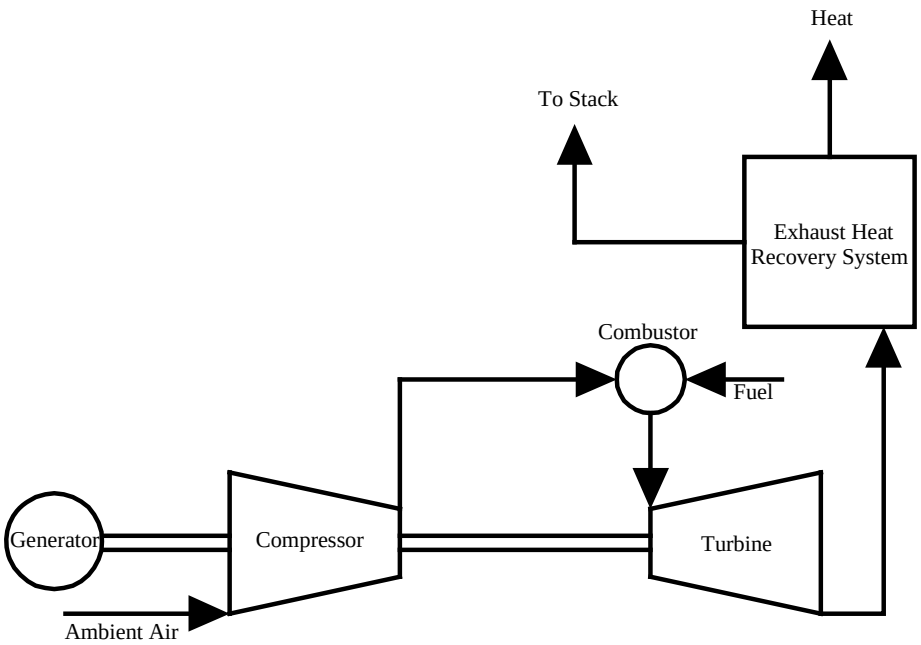


Figure 11: Simple-Cycle Gas Turbine

Source: DE Solutions

State of the art gas turbines currently control emissions to ARB 2007 levels using lean pre-mix combustion techniques coupled with selective catalytic reduction (SCR) of the exhaust stream. Catalytic combustion, which has the capability to reach ARB emission levels without after-treatment, has been introduced in the Kawasaki 1.5 MW turbine.

Recuperated gas turbines—until recently a configuration unique to microturbines—are now being developed in multi-megawatt sizes. The recuperator preheats the combustion air with a portion of the exhaust heat appreciably increasing electric efficiency. Recuperated turbines operate at lower pressure ratios and combustor temperatures reducing NO_x formation. Recuperated turbine dry low emission (DLE) combustors show potential to meet ARB emission levels without any after-treatment.

Recuperated gas turbines exhibit lower exhaust temperatures and notably lower overall CHP efficiencies than their simple-cycle counterparts. They are a better fit for commercial and institutional applications where the heat requirements are modest relative to the power demand.

Gas turbine cost and performance assumptions are shown in **Table 3**, **Table 4**, and **Table 5**.

Table 3: Gas Turbine Technology in the 1–5 MW Size Range

CHP System	Characteristic/Year Available	2009	2014	2019
3000 KW GT	Installed Costs, $/kW	1,690	1,560	1,300
	CA Installed Costs	1,876	1,732	1,443
	Heat Rate, Btu/kWh	13,100	12,650	11,500
	Electric Efficiency, %	26.0	27.0	29.7
	Thermal Output, Btu/kWh	5018	4750	4062
	Overall Efficiency, %	64.4	64.5	65.0
	Power to Heat	0.68	0.72	0.84
	O&M Costs, $/kWh	0.0074	0.0065	0.006
	NO_x Emissions, ppm (w/o AT)	15	9	5
	NO_x Emissions, lbs/MWh (w/o AT)	0.68	0.38	0.2
	NO_x Emission, lb/MWh (w/ AT)	0.07	0.07	0.07
	After-treatment Cost, $/kW	210	175	150

Source: ICF International

Table 4: Gas Turbine Technology in the 5–20 MW Size Range

CHP System	Characteristic/Year Available	2009	2014	2019
10 MW GT	Installed Costs, $/kW	1,298	1,278	1,200
	CA Installed Costs	1,441	1,419	1,333
	Heat Rate, Btu/kWh	11,765	10,800	9,950
	Electric Efficiency, %	29.0	31.6	34.3
	Thermal Output, Btu/kWh	4674	4062	3630
	Overall Efficiency, %	68.7	69.2	70.8
	Power to Heat	0.73	0.84	0.94
	O&M Costs, $/kWh	0.007	0.006	0.005
	NO_x Emissions, ppm (w/o AT)	15	9	5
	NO_x Emissions, lbs/MWh (w/o AT)	0.68	0.38	0.2
	NO_x Emission, lb/MWh (w/ AT)	0.07	0.07	0.07
	After-treatment Cost, $/kW	140	125	100

Source: ICF International

Table 5: Gas Turbine Technology in the >20 MW Size Range

CHP System	Characteristic/Year Available	2009	2014	2019
40 MW GT	Installed Costs, $/kW	972	944	916
	CA Installed Costs	1,079	1,048	1,017
	Heat Rate, Btu/kWh	9,220	8,865	8,595
	Electric Efficiency, %	37.0	38.5	39.7
	Thermal Output, Btu/kWh	3189	3019	2892
	Overall Efficiency, %	71.6	72.5	73.3
	Power to Heat	1.07	1.13	1.18
	O&M Costs, $/kWh	0.004	0.004	0.004
	NO_x Emissions, ppm (w/o AT)	15	5	3
	NO_x Emissions, lbs/MWh (w/o AT)	0.55	0.2	0.1
	NO_x Emission, lb/MWh (w/ AT)	0.06	0.06	0.06
	After-treatment Cost, $/kW	90	75	40

Source: ICF International

2.2.3. Microturbines

Several companies have developed commercial microturbine products, ranging in size from 30 kW to 250 kW, and are in the early stages of market entry. Microturbines' potential for low emissions, reduced maintenance, and simplicity could make on-site generation more feasible for many smaller commercial and industrial operations if plans for cost reduction are realized. The electric efficiency of microturbines are in the 25 to 30% (HHV) range but are derated (capacity and efficiency) at higher ambient temperatures (> 80°F) and at high elevations.

Figure 12 depicts the microturbine cycle. Recuperated turbines are lower pressure ratio machines and operate at lower turbine inlet temperatures than their simple-cycle turbine counterparts. Both of these features lessen emission formation. Microturbines equipped with lean pre-mixed combustors are able to reach ARB 2007 levels without the need for any after-treatment. Because the recuperator utilizes much of the exhaust heat, the temperature and quantity of recovered heat from microturbines are limited.

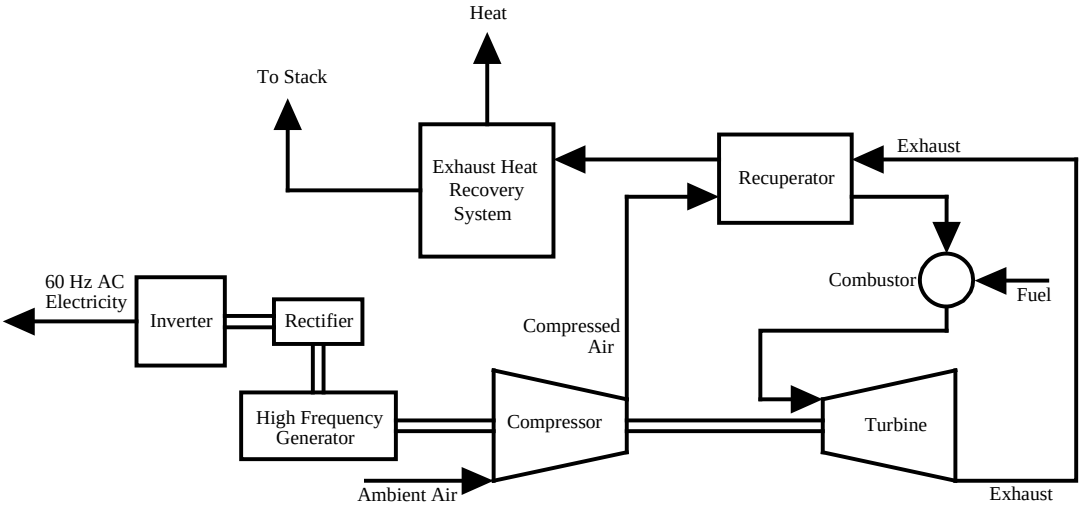


Figure 12: Microturbine-Based CHP System

Source: NREL

The microturbine cost and performance assumptions are shown in

Table 6 and **Table 7.**

Table 6: Microturbine Technology in the 50–500 kW Size Range

CHP System	Characteristic/Year Available	2009	2014	2019
65 kW	Installed Costs, $/kW	2,739	2,037	1,743
	CA Installed Costs	3,040	2,261	1,935
	Heat Rate, Btu/kWh	13,542	12,500	11,375
	Electric Efficiency, %	25.2	27.3	30.0
	Thermal Output, Btu/kWh	6277	5350	4500
	Overall Efficiency, %	71.5	70.1	69.6
	Power to Heat	0.54	0.64	0.76
	O&M Costs, $/kWh	0.022	0.016	0.012
	NO_x Emissions, lbs/MWh (w/o AT)	0.17	0.14	0.13
	NO_x Emissions, lbs/MWh (w/o AT) CHP Credit	0.06	0.05	0.06
	After-treatment Cost, $/kW			

Source: ICF International

Table 7: Microturbine Technology in the 500 kW–1 MW Size Range

CHP System	Characteristic/Year Available	2009	2014	2019
250 KW-use multiple units	Installed Costs, $/kW	2,684	2,147	1,610
	CA Installed Costs	2,979	2,383	1,788
	Heat Rate, Btu/kWh	12,290	11,750	10,825
	Electric Efficiency, %	27.8	29.0	31.5
	Thermal Output, Btu/kWh	4800	4300	3700
	Overall Efficiency, %	66.8	65.6	65.7
	Power to Heat	0.71	0.79	0.92
	O&M Costs, $/kWh	0.015	0.013	0.012
	NO_X Emissions, lbs/MWh (w/o AT)	0.14	0.13	0.13
	NO_X Emissions, lbs/MWh (w/o AT) CHP Credit	0.06	0.06	0.06
	After-treatment Cost, $/kW			

Source: ICF International

2.2.4. Fuel Cells

Fuel cell systems with applications in electric power generation, motor vehicles, portable electronic equipment, and military/aerospace applications are largely in research, development, testing and other pre-commercialization stages. Fuel cells produce power electrochemically, more like a battery than like a conventional generating system. Unlike a storage battery, however, which produces power from stored chemicals, fuel cells produce power when hydrogen fuel is delivered to the anode of the cell and oxygen from the atmosphere is delivered to the cathode. The resultant chemical reactions at each electrode create a stream of electrons (or direct current) that flows between the oppositely charged electrodes of the cell. The hydrogen fuel can come from a variety of sources, but the most economic is through reforming of natural gas.

Figure 13 illustrates a typical fuel cell process.

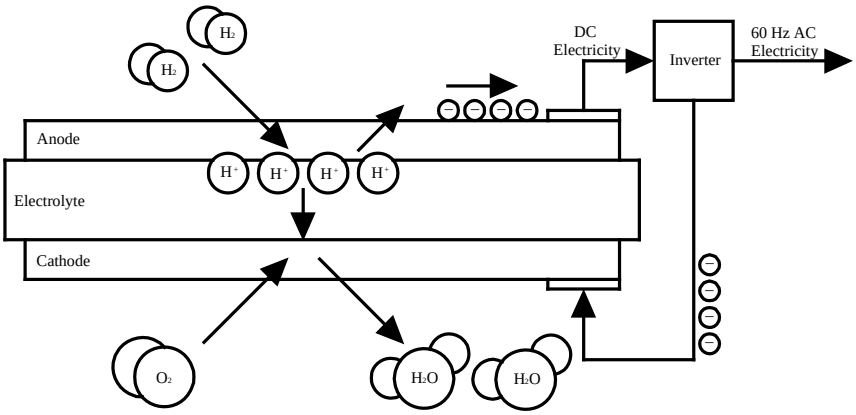


Figure 13: Fuel Cell Electrochemical Process

Source: NREL

There are several different liquid and solid media that can be used to create the fuel cell's electrochemical reactions: phosphoric acid (PAFC), molten carbonate (MCFC), solid oxide (SOFC), and proton exchange membrane (PEM). Each of these media comprises a distinct fuel cell technology with its own performance characteristics and development schedule. PAFCs are in early commercial market development with 200 kW units delivered to more than 300 customers worldwide. The MCFC is also on early market entry.

Fuel cells promise higher electric efficiencies than generation technologies based on prime movers such as reciprocating engines or turbines. In addition fuel cells are inherently quiet and extremely clean running. Like microturbines, fuel cells require power electronics to convert direct current output to 60-Hz alternating current. Many fuel cell technologies are modular and capable of application in small commercial and even residential markets. Specific technologies such as the MCFC utilize high temperatures in larger sized systems that would be well-suited to industrial CHP applications. Fuel cell installations to date have benefited by government support to counter current high costs. Otherwise, markets have been limited to niche markets such as very high electric rate areas requiring near zero emissions, and in some high power reliability applications. Substantial price reductions are necessary for meaningful market acceptance to occur.

Fuel cell heat quality is linked to the primary process temperature and the degree of internal heat recovery for reformer heating and/or electric bottoming cycles. The heat characteristics of fuel cells vary by technology but are generally limited. Either the quantity of available heat is low because of the emphasis placed on electric efficiency or the temperature of the heat is low, limiting heat applicability.

Fuel cell cost and performance assumptions are shown in **Table 8**, **Table 9,** and **Table 10**.

Table 8: Fuel Cell Technology in the 50–500 kW Size Range

CHP System	Characteristic/Year Available	2009	2014	2019
200/400 kW PAFC (assumes all high grade and 50% low grade thermal utilized)	Installed Costs, $/kW	6,310	4,782	3,587
	CA Installed Costs	7,004	5,308	3,981
	Heat Rate, Btu/kWh	9,475	9,475	9,000
	Electric Efficiency, %	36.0	36.0	37.9
	Thermal Output, Btu/kWh	2923	2923	2800
	Overall Efficiency, %	66.9	66.9	69.0
	Power to Heat	1.17	1.17	1.22
	O&M Costs, $/kWh	0.038	0.017	0.015
	NO_x Emissions, lbs/MWh (w/o AT)	0.04	0.035	0.035
	After-treatment Cost, $/kW	n.a.	n.a.	n.a.

Source: ICF International

Table 9: Fuel Cell Technology in the 500 kW–1 MW Size Range

CHP System	Characteristic/Year Available	2009	2014	2019
300 kW MCFC	Installed Costs, $/kW	5,580	4,699	3,671
	CA Installed Costs	6,194	5,216	4,075
	Heat Rate, Btu/kWh	8,022	7,700	7,300
	Electric Efficiency, %	42.5	44.3	46.7
	Thermal Output, Btu/kWh	1600	1500	1300
	Overall Efficiency, %	62.5	63.8	64.5
	Power to Heat	2.13	2.27	2.62
	O&M Costs, $/kWh	0.035	0.02	0.015
	NO_x Emissions, lbs/MWh (w/o AT)	0.01	0.01	0.01
	After-treatment Cost, $/kW	n.a.	n.a.	n.a.

Source: ICF International

Table 10: Fuel Cell Technology in the 1–5 MW Size Range

CHP System	Characteristic/Year Available	2009	2014	2019
1500 kW MCFC	Installed Costs, $/kW	5,250	4,523	3,554
	CA Installed Costs	5,828	5,021	3,945
	Heat Rate, Btu/kWh	8,022	7,500	6,820
	Electric Efficiency, %	42.5	45.5	50.0
	Thermal Output, Btu/kWh	1583	1400	1100
	Overall Efficiency, %	62.3	64.2	66.2
	Power to Heat	2.15	2.44	3.10
	O&M Costs, $/kWh	0.032	0.019	0.015
	NO_x Emissions, lbs/MWh (w/o AT)	0.01	0.01	0.01
	After-treatment Cost, $/kW	n.a.	n.a.	n.a.

Source: ICF International

2.2.5. Absorption Chillers

In the cooling markets, an additional cost was added to reflect the costs of adding chiller capacity to the CHP system. These costs are a function of the size of the absorption chiller, which in turn depends on the amount of usable waste heat that the CHP system produces. A curve fitting approach was used as shown in **Figure 14**. Within each CHP size bin the costs for adding absorption cooling capacity equal to the thermal output of each system is shown in **Table 11**.

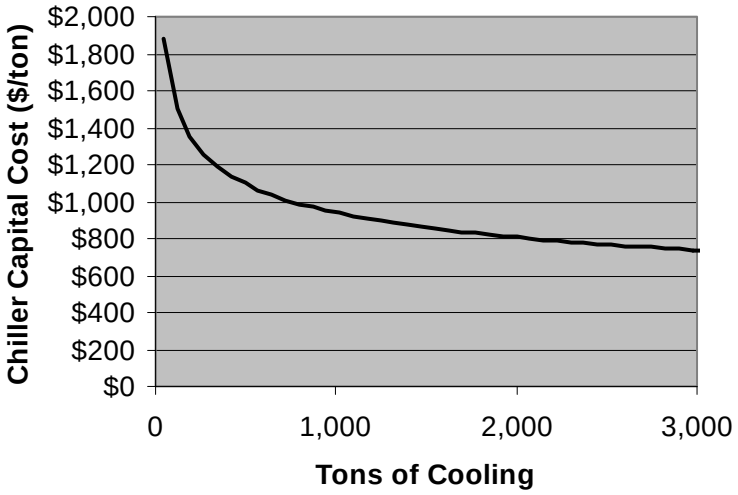


Figure 14: Absorption Chiller Cost Fitting Curve

Source: ICF International

Table 11: Range of Absorption Chiller Costs by CHP Size

CHP System Size	Additional Cost for Absorption Chiller
50 - 500 kW	$390 - 530/kW
500 -1,000 kW	$275 - 500/kW
1 - 5 MW	$110 - 270/kW
5 - 20 MW	$65 - 110/kW
> 20 MW	$45/kW

Source: ICF International

2.3. Natural Gas and Electricity Price Trends

The delivered natural gas and electricity prices are a major determinant of the economic value of CHP at a given site. This section describes the energy price assumptions over the 20-year forecast period.

2.3.1. Natural Gas Prices

The focus of the CHP Market Model is CHP at industrial facilities and commercial and institutional buildings. In the these markets, the CHP systems are almost exclusively fueled by natural gas and the thermal energy provided by the CHP system displaces primarily natural gas boiler fuel.

After reaching nearly $12/MMBtu in July 2008, natural gas prices for electric power generation in California have dropped below $4/MMBtu by April 2009, as shown in **Figure 15.** These low prices create an economic stimulus for the development of additional CHP projects. However, price volatility and frequent price spikes as occurred in 2006 and 2008 add to project financial risk and require long-term contracting of fuel supply.

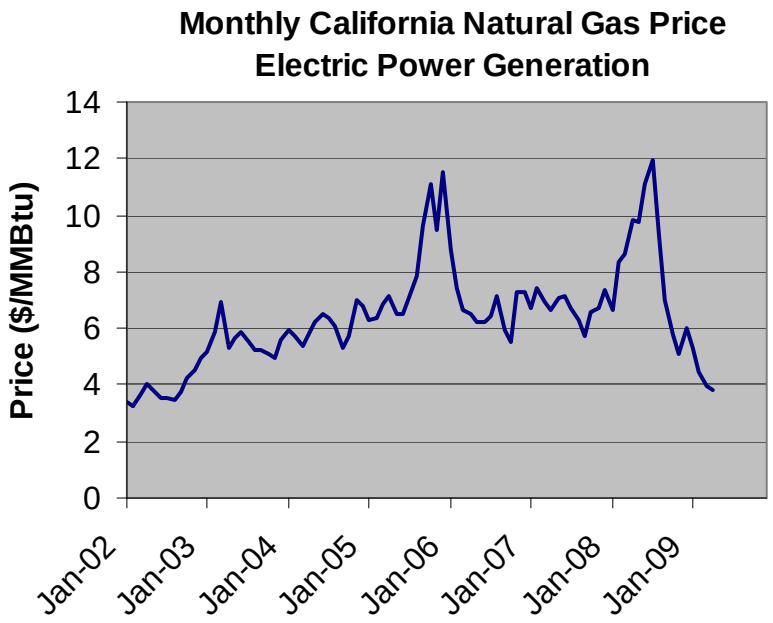


Figure 15: Natural Gas Prices for Power Generation in California (2002-2009)

Source: EIA[12]

The current trends in natural gas prices have affected the long-term outlook for natural gas prices as well. The project team chose to use the latest long-term gas price forecast from the Energy Information Administration (EIA.) This forecast, released in April 2009, is called the *Updated Reference Case with ARRA* (American Recovery and Reinvestment Act.)[13] This case, informally known as the *Stimulus Case*, accurately reflects the current and near-term drop in natural gas prices that was not reflected in EIA's March 2009 *Reference Case*. The price track chosen from the Stimulus Case that is most relevant to California and to CHP is the delivered natural gas price to electric power generators for the California sub-region of the Western Electricity Coordinating Council (WECC).

12 Energy Information Administration, On-line natural gas monthly price statistics.
13 Energy Information Administration, On-line 2009 Annual Energy Outlook Results, http://www.eia.doe.gov/oiaf/servicerpt/stimulus/aeostim.html, April 2009.

Figure 16 shows this natural gas price track compared to the electric power generation price that was assumed in the 2005 CHP study.[14] The figure shows that the outlook for natural gas prices over the next 10 years is for significantly lower prices. There appears to be a convergence beyond the 10-year time frame of the very long-term outlook for continued real increases in natural gas prices.

The natural gas price for electric power generators was assumed to be the price that CHP operators would receive under special natural gas pricing rules for CHP. Delivered natural gas prices for boiler fuel were assumed to be $1.20/MMBtu higher. This additional mark-up is based on analysis of the existing PG&E retail natural gas tariffs that show $0.18/MMBtu markup on commodity costs for CHP and $1.38/MMBtu markup on commodity costs for boiler fuel.

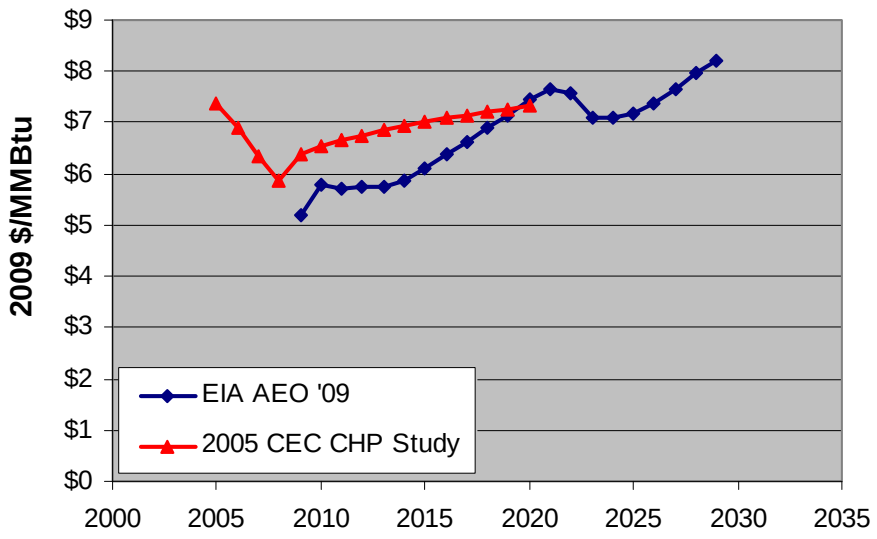


Figure 16: California Natural Gas Price Forecast for Electric Power Generation

Source: EIA

2.3.2. Electricity Prices

The project team analyzed the current electricity tariffs applicable for the range of customer sizes appropriate to the selection of CHP from 50 kW to larger than 20 MW. Current electricity tariffs were analyzed for the three major investor-owned utilities: SCE, PG&E, and San Diego Gas & Electric (SDG&E), and the two largest municipal utilities: Los Angeles Department of Water and Power (LADWP) and Sacramento Municipal Utility District (SMUD). Other utility rates in the state were not analyzed. Potential CHP customers in these territories were assigned to two miscellaneous categories, *Other South* and *Other North*. Both of these miscellaneous categories were assumed to have average prices that are 5% higher than the average of SMUD and LADWP.

14 *Assessment of CHP Market and Policy Options for Increased Penetration*, April 2005. California Energy Commission, CEC-500-2005-060-D.

The approach used to forecast rates consists of the following steps:

- Analysis of retail rates at three load factors reflecting high load factor (nearly continuous) CHP operation, low load factor CHP operation assuming a peak weighted 4500 hours per year, and an air-conditioning load factor based on on-peak operation approximately 2000 hours per year depending on the tariff.
- Analysis of the avoided costs of CHP operation at both high and low load factor operation. Avoided air-conditioning costs are at the calculated retail rate because there are no standby related charges applied to the thermal output of the CHP system.
- Forecast of rates assuming constant real transmission and distribution related costs and generation costs that escalate in real terms based on the assumed marginal cost of power generation as determined by a natural gas-fired combined cycle power generation plant.

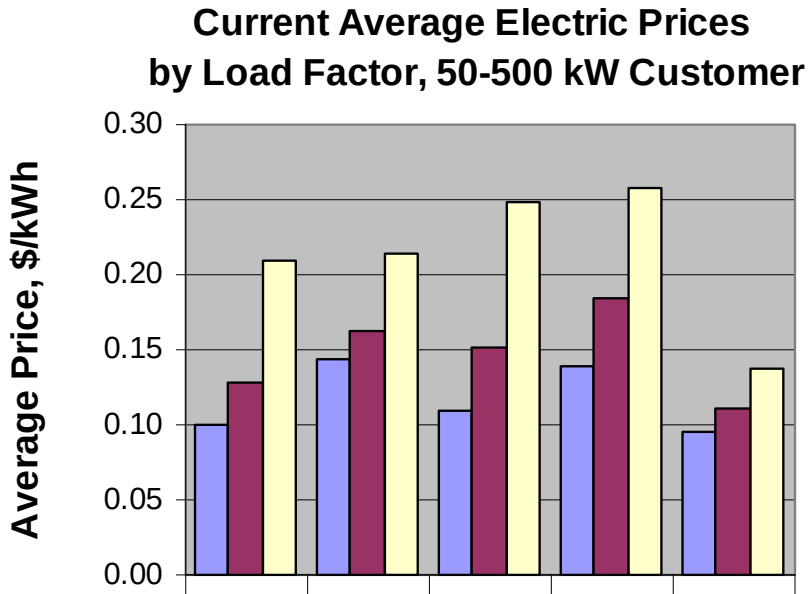
Existing Retail Rates

The existing retail rates by size classification are shown in

Figure 17**-20**.

The three IOUs have generally higher rates than the two municipal utilities. SMUD has the lowest rates in all size and load categories.

- In the high load factor category, PG&E has the highest average rates for the 50-500 kW size class, and SDG&E has the highest rates for all larger size classes.
- In the low load factor category, SDG&E has the highest average rates in all sizes. The low load factor rates are 25–30% higher than the average high load factor rates, depending on the size category.
- SCE and SDG&E have the highest average air conditioning rates. The average air conditioning rates are 44–49% higher than the average high load factor rates, depending on the size category.

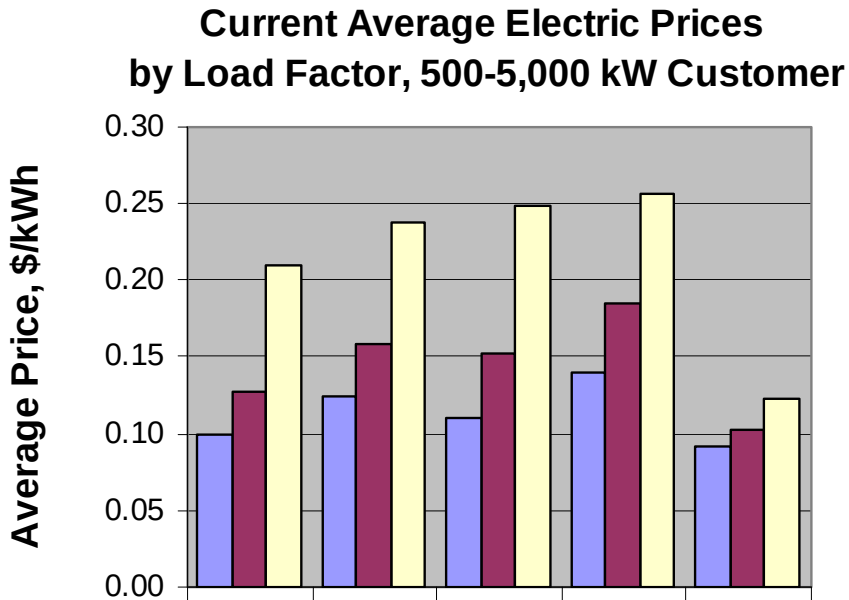


	LADWP	PG&E	SCE	SDG&E	SMUD
High Load Factor	$0.0995	$0.1438	$0.1098	$0.1398	$0.0951
Low Load Factor	$0.1279	$0.1630	$0.1511	$0.1847	$0.1109
Peak AC	$0.2097	$0.2138	$0.2487	$0.2578	$0.1373

Rate Classification:
LADWP: A-2b Secondary
PG&E: A-10 TOU Secondary
SCE: GS 8-TOU Secondary
SDG&E: AL-TOU Secondary
SMUD: GS-TOU3 Secondary

Figure 17: Average Retail Electric Prices by Load Factor, 50-500 kW

Source: ICF Analysis of Utility Tariffs

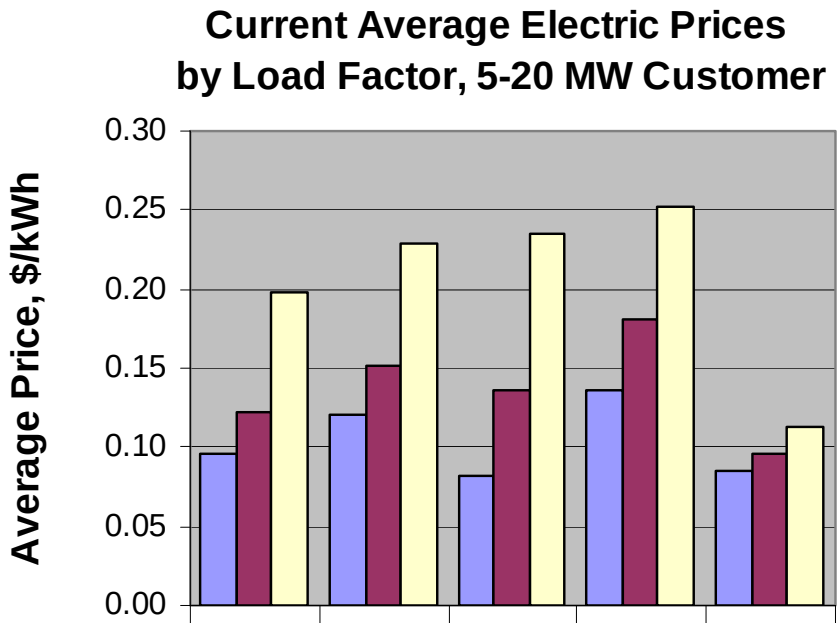


	LADWP	PG&E	SCE	SDG&E	SMUD
High Load Factor	$0.0995	$0.1243	$0.1108	$0.1395	$0.0917
Low Load Factor	$0.1279	$0.1582	$0.1523	$0.1842	$0.1033
Peak AC	$0.2097	$0.2385	$0.2490	$0.2568	$0.1226

Rate Classification:
LADWP: A-3c Primary
PG&E: E-20 Secondary
SCE: GS 8-TOU Primary
SDG&E: AL-TOU Secondary
SMUD: GS-TOU1 Secondary

Figure 18: Average Retail Electric Prices by Load Factor, 500-5,000 kW

Source: ICF Analysis of Utility Tariffs

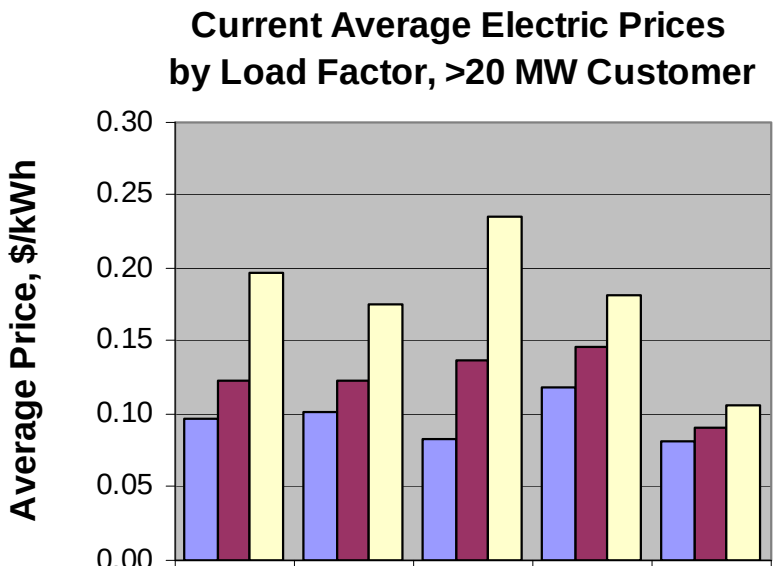


	LADWP	PG&E	SCE	SDG&E	SMUD
High Load Factor	$0.0964	$0.1202	$0.0827	$0.1366	$0.0847
Low Load Factor	$0.1224	$0.1522	$0.1363	$0.1805	$0.0952
Peak AC	$0.1976	$0.2281	$0.2353	$0.2517	$0.1127

Rate Classification:
LADWP: A-3a Subtransmission
PG&E: E-20 Primary
SCE: GS 8-TOU Transmission
SDG&E: AL-TOU Primary
SMUD: GS-TOU1 Primary

Figure 19: Average Retail Electric Prices by Load Factor, 5-20 MW

Source: ICF Analysis of Utility Tariffs



	LADWP	PG&E	SCE	SDG&E	SMUD
High Load Factor	$0.0964	$0.1013	$0.0827	$0.1189	$0.0817
Low Load Factor	$0.1224	$0.1234	$0.1363	$0.1468	$0.0907
Peak AC	$0.1976	$0.1750	$0.2353	$0.1816	$0.1058

Rate Classification:
LADWP: A-3a Subtransmission
PG&E: E-20 Tranasmission
SCE: GS 8-TOU Transmission
SDG&E: AL-TOU Subtransmission
SMUD: GS-TOU1 Transmission

Figure 20: Average Retail Electric Prices by Load Factor, Greater Than 20 MW

Source: ICF Analysis of Utility Tariffs

Average CHP Savings Rate

Retail electric customers installing CHP within the three IOUs must pay departing load customer responsibility surcharges (CRS), although there are a number of exemptions that reduce this amount for customers with CHP systems that meet specified efficiency and emissions targets. All CHP customers must pay nuclear decommissioning and public purpose programs charges. Customers with CHP that meets the Federal Energy Regulation Commission QF efficiency targets are not required to pay the Competitive Transition Charges. Customers with CHP greater than 1 MW must also pay the DWR Bond Surcharge, whereas customers with qualifying CHP system below this size are exempt. Applicable surcharges for CHP customers typically are less than 1 cent/kWh of departing load (the generation output of the CHP system).

LADWP and SMUD both have standby demand or service charges that the CHP customer must pay on the rated CHP capacity each month. The impact of these charges for SMUD is about 1 cent/kWh. LADWP has the highest difference between average retail rates and average CHP savings of about 1.5 cents/kWh. For the IOUs, the difference between average retail rates and the effective avoided rate for kWh displaced by the output of the CHP system is about 2 cents/kwh, which includes departing load surcharges and, also, the impacts of demand charges incurred when the CHP system goes down during peak hours. CHP systems must be shut down for periodic maintenance; this maintenance is usually undertaken off-peak to minimize economic losses. CHP systems also have forced outages that can occur anytime. For this analysis, the CHP system was assumed to go down once during the summer months and twice during the winter months. The amount and distribution of assumed downtime is considered to accurately reflect the capabilities of the CHP systems in the analysis.

Figure 21 shows the difference between average retail rates and CHP savings rates by utility for the 50-500 kW size range. Although SMUD has the lowest average retail rates, LADWP has the lowest avoided CHP rates by virtue of their higher standby charges and rules for demand charges. The average CHP energy savings per kWh are shown in **Table 12** by size, load factor, and utility. As previously indicated, the entire average air conditioning retail rate can be saved through the use of thermally activated cooling from a CHP system, which means that the AC retail rate and the CHP savings are the same.

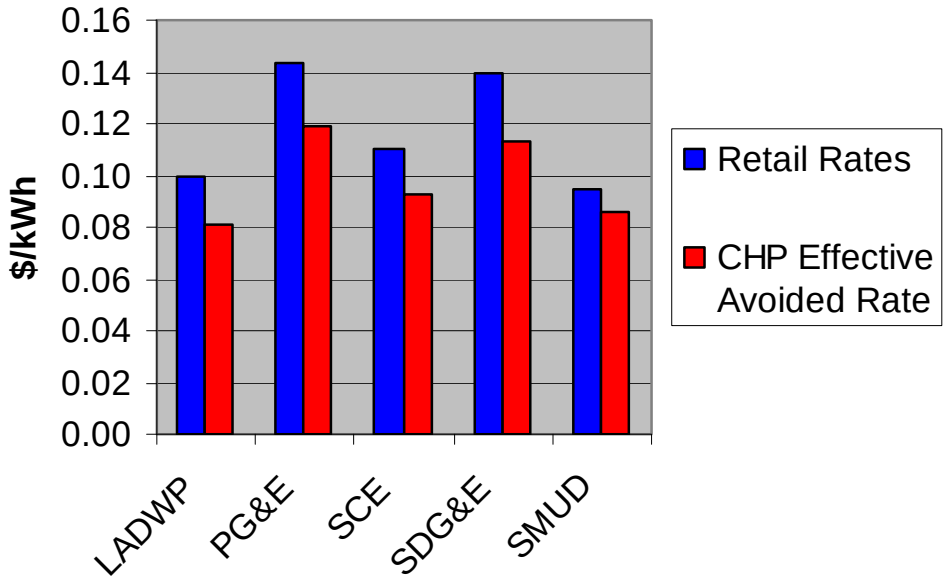


Figure 21: Average Retail Rates and Avoided CHP Energy Costs for Continuous 50-500 kW Customer

Source: ICF Analysis of published utility tariffs

Table 12: CHP Avoided Electric Costs by Size and Utility

Size	Load Factor	LADWP	PG&E	SCE	SDG&E	SMUD
50–500 kW	High Load Factor	$0.081	$0.119	$0.092	$0.113	$0.086
	Low Load Factor	$0.092	$0.133	$0.120	$0.148	$0.093
500–5,000 kW	High Load Factor	$0.088	$0.095	$0.094	$0.119	$0.083
	Low Load Factor	$0.102	$0.118	$0.122	$0.154	$0.087
5–20 MW	High Load Factor	$0.085	$0.093	$0.070	$0.116	$0.078
	Low Load Factor	$0.097	$0.117	$0.101	$0.151	$0.083
> 20 MW	High Load Factor	$0.085	$0.080	$0.070	$0.106	$0.079
	Low Load Factor	$0.097	$0.098	$0.101	$0.133	$0.084

Source: ICF International

Electric Rate Escalation

The current electric tariffs and CHP avoided costs are escalated into the following four periods: 2009, 2014, 2019, and 2024. Each of these rates is used to determine the five-year cumulative market penetration for 2014, 2019, 2024, and 2029. It is assumed that the transmission and delivery portion of the rates is fixed in real dollars and therefore does not change throughout the forecast period. The generation component of the CHP effective avoided rates is adjusted based on the assumed escalation in marginal utility generation costs. This marginal cost is represented by a natural gas-fired combined cycle power plant. **Figure 22** shows the assumed marginal generation costs using the natural gas price track shown previously in **Figure 16** and the power plant cost and performance assumptions for a conventional gas-fired combined cycle power plant (inset) based on the Energy Commission's draft staff report *Central Station Electricity Generation*.[15]

15 *Guidelines for Certification of Combined Heat and Power Under the Waste Heat and Carbon Emissions Reduction Act*, Draft Guidelines, CEC-200-2009-060-D.

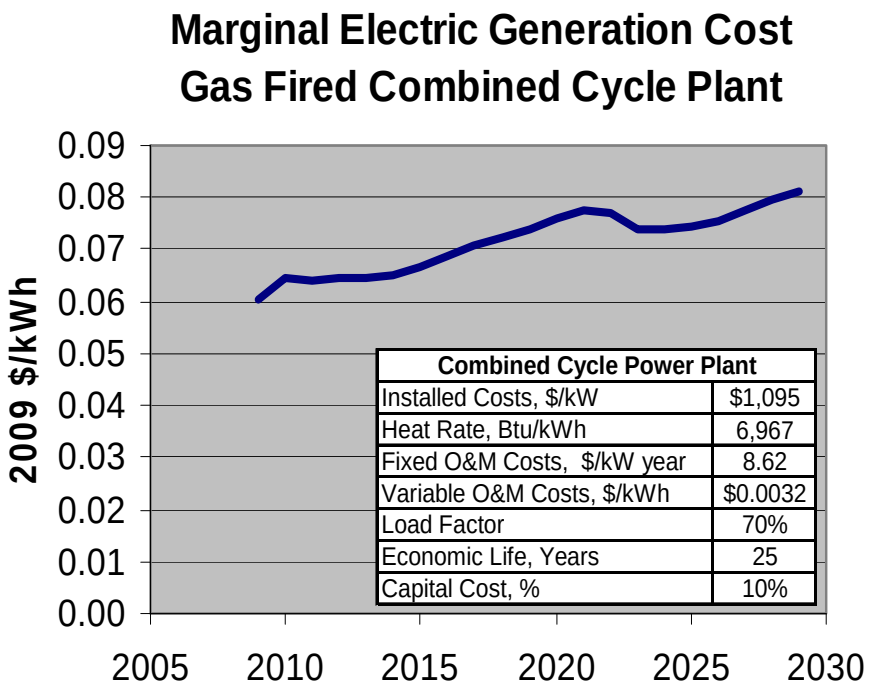


Figure 22: Real Escalation in Marginal Electric Utility Generation

Source of Combined-Cycle Power Plant Assumptions[16]

Prices in the model are taken in five-year averages for the four forecast periods within the 20-year time horizon. **Figure 23** shows the price escalation for the high load factor 50-500 kW size category by utility. Prices escalate in real terms for the first 15 years and then are stable for the last five-year forecast period. All the CHP effective avoided average prices are shown in **Table 13**, **Table 14,** and **Table 15.**

16 *Comparative Costs of Central Station Electricity Generation*, Draft Staff Report, August 2009. CEC-200-2009-017-SD.

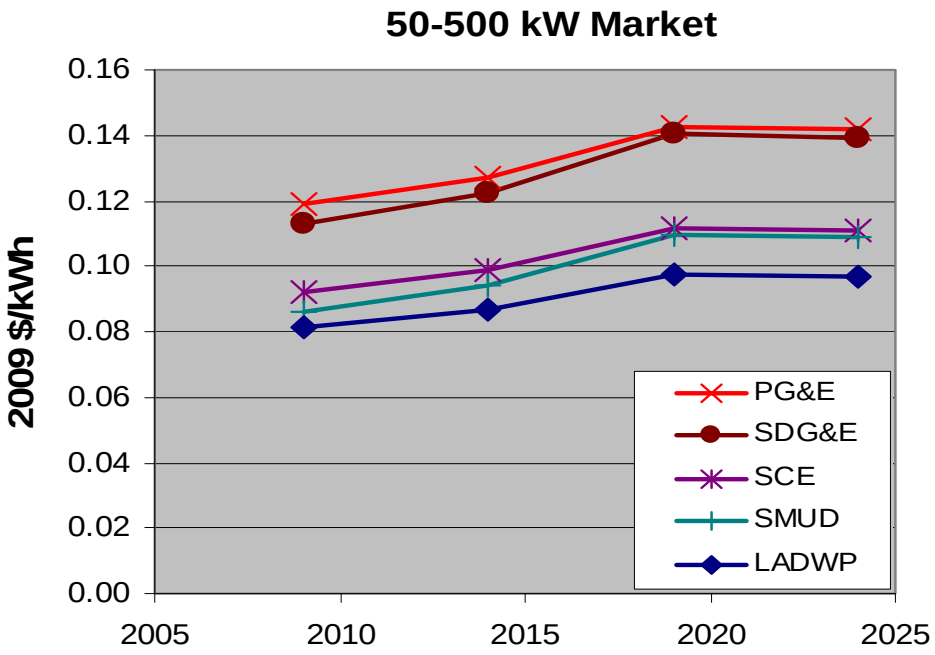


Figure 23: Average Electricity Cost Savings High Load Factor CHP: 50-500 kW

Source: ICF International

Table 13: High Load Factor, Average CHP Effective Avoided Rate, 2009 $/kWh

		Average CHP Avoided Price, $/kWh						
Customer CHP Size	**Time Period**	**LADWP**	**Other North**	**Other South**	**PG&E**	**SCE**	**SDG&E**	**SMUD**
50-500 kW	2009-2014	0.081	0.088	0.088	0.119	0.092	0.113	0.086
	2015-2019	0.087	0.095	0.095	0.127	0.099	0.122	0.094
	2020-2024	0.097	0.109	0.109	0.143	0.112	0.140	0.109
	2024-2029	0.097	0.108	0.108	0.142	0.111	0.139	0.109
500-5,000 kW	2009-2014	0.088	0.090	0.090	0.095	0.094	0.119	0.083
	2015-2019	0.094	0.097	0.097	0.103	0.101	0.128	0.091
	2020-2024	0.105	0.111	0.111	0.118	0.114	0.146	0.106
	2024-2029	0.104	0.110	0.110	0.118	0.113	0.145	0.106
5-20 MW	2009-2014	0.085	0.085	0.085	0.093	0.070	0.116	0.078
	2015-2019	0.090	0.092	0.092	0.101	0.075	0.125	0.085
	2020-2024	0.101	0.106	0.106	0.116	0.085	0.143	0.100
	2024-2029	0.101	0.105	0.105	0.115	0.084	0.142	0.099
> 20 MW	2009-2014	0.085	0.086	0.086	0.080	0.070	0.106	0.079
	2015-2019	0.090	0.092	0.092	0.087	0.075	0.116	0.086
	2020-2024	0.101	0.106	0.106	0.102	0.085	0.133	0.100
	2024-2029	0.101	0.105	0.105	0.102	0.084	0.132	0.100

Source: ICF International

Table 14: Low Load Factor, Average CHP Effective Avoided Rate, 2009 $/kWh

		Average CHP Avoided Price, $/kWh						
Customer CHP Size	**Time Period**	**LADWP**	**Other North**	**Other South**	**PG&E**	**SCE**	**SDG&E**	**SMUD**
50-500 kW	2009-2014	0.092	0.097	0.097	0.133	0.120	0.148	0.093
	2015-2019	0.098	0.105	0.105	0.143	0.128	0.160	0.102
	2020-2024	0.110	0.120	0.120	0.162	0.144	0.182	0.119
	2024-2029	0.109	0.119	0.119	0.161	0.144	0.181	0.118
500-5,000 kW	2009-2014	0.102	0.100	0.100	0.118	0.122	0.154	0.087
	2015-2019	0.109	0.107	0.107	0.128	0.130	0.166	0.095
	2020-2024	0.123	0.123	0.123	0.147	0.147	0.188	0.111
	2024-2029	0.122	0.122	0.122	0.146	0.146	0.187	0.111
5-20 MW	2009-2014	0.097	0.094	0.094	0.117	0.101	0.151	0.083
	2015-2019	0.104	0.102	0.102	0.127	0.107	0.163	0.090
	2020-2024	0.117	0.117	0.117	0.145	0.120	0.185	0.105
	2024-2029	0.116	0.116	0.116	0.144	0.119	0.184	0.105
> 20 MW	2009-2014	0.097	0.095	0.095	0.098	0.101	0.133	0.084
	2015-2019	0.104	0.103	0.103	0.107	0.107	0.144	0.092
	2020-2024	0.117	0.118	0.118	0.125	0.120	0.166	0.108
	2024-2029	0.116	0.117	0.117	0.124	0.119	0.165	0.107

Source: ICF International

Table 15: Air Conditioning, Average CHP Effective Avoided Rate, 2009 $/kWh

		Average CHP Avoided Price, $/kWh						
Customer CHP Size	**Time Period**	**LADWP**	**Other North**	**Other South**	**PG&E**	**SCE**	**SDG&E**	**SMUD**
50-500 kW	2009-2014	0.210	0.178	0.178	0.214	0.249	0.258	0.130
	2015-2019	0.223	0.190	0.190	0.227	0.261	0.271	0.139
	2020-2024	0.248	0.213	0.213	0.253	0.284	0.296	0.158
	2024-2029	0.247	0.212	0.212	0.252	0.283	0.295	0.157
500-5,000 kW	2009-2014	0.210	0.169	0.169	0.238	0.249	0.257	0.113
	2015-2019	0.223	0.181	0.181	0.252	0.261	0.270	0.121
	2020-2024	0.248	0.203	0.203	0.278	0.285	0.295	0.138
	2024-2029	0.247	0.202	0.202	0.277	0.284	0.294	0.137
5-20 MW	2009-2014	0.198	0.159	0.159	0.228	0.235	0.252	0.106
	2015-2019	0.210	0.170	0.170	0.241	0.245	0.265	0.114
	2020-2024	0.234	0.191	0.191	0.266	0.264	0.290	0.130
	2024-2029	0.233	0.190	0.190	0.265	0.263	0.289	0.129
> 20 MW	2009-2014	0.198	0.159	0.159	0.175	0.235	0.182	0.106
	2015-2019	0.210	0.170	0.170	0.188	0.245	0.195	0.114
	2020-2024	0.234	0.191	0.191	0.212	0.264	0.220	0.130
	2024-2029	0.233	0.190	0.190	0.211	0.263	0.218	0.129

Source: ICF International

Export Pricing: Feed-In Tariff

All of the pricing discussed in the previous sections relate to the retail rates that customers are charged for buying utility-supplied power and the average effective avoided rates that a customer can save by operating CHP to displace on-site electric load. CHP-produced power can also be exported to the grid. The price paid for this exported power can be determined by a variety of mechanisms. Under PURPA, utilities are required to purchase power from CHP systems at their avoided costs. Utilities in California have established their short-run avoided costs, but these costs currently range from 3 to 3.5 cent/kWh, making them too low to attract any CHP power sales. Large existing CHP systems that are qualifying facilities (QFs) under PURPA have contracts to supply power to the utilities. However, these contracts are not being offered for new CHP generation. A final mechanism for exporting power to the grid is a special feed-in-tariff (FIT) as has been established for renewable power. AB 1613 requires the IOUs to also establish a CHP-FIT for systems up to 20 MW. To date, the CHP-FIT has not been established.

To estimate the expected market penetration for CHP export, the study team created separate export price forecasts for systems eligible for AB 1613 (systems smaller than 20 MW) and for systems larger than 20 MW that will most likely contract directly with utilities to export power.

Feed-In Tariff for Systems up to 20 MW

- SMUD has a proposed CHP-FIT for systems up to 5 MW. Export prices are specified for nine time periods reflecting seasonal peak and off-peak prices. In this and all other cases, the exported power is assumed to occur continuously at a constant rate. The weighted average of the 2009 10-year contract rate over an entire year is equal to 8.33 cents/kWh. This study assumed that this rate applies also to systems up to 20 MW as in the AB 1613 eligibility rules for IOUs. The study also assumed that this price applies to LADWP and to the North and South Other regions. Escalation is assumed to be proportional to the escalation in each applicable utility region's retail rates.
- The assumed FIT for the IOUs is based on an analysis of the PG&E and SCE FIT for renewable power. The 15-year 2009 market price referent (MPR) of $0.1057/kWh is used. When applied as a constant supply during the different time periods, the average value is equal to 95% of the MPR. Escalation of this FIT is assumed to occur proportionally to the escalation in the utility's retail rates.

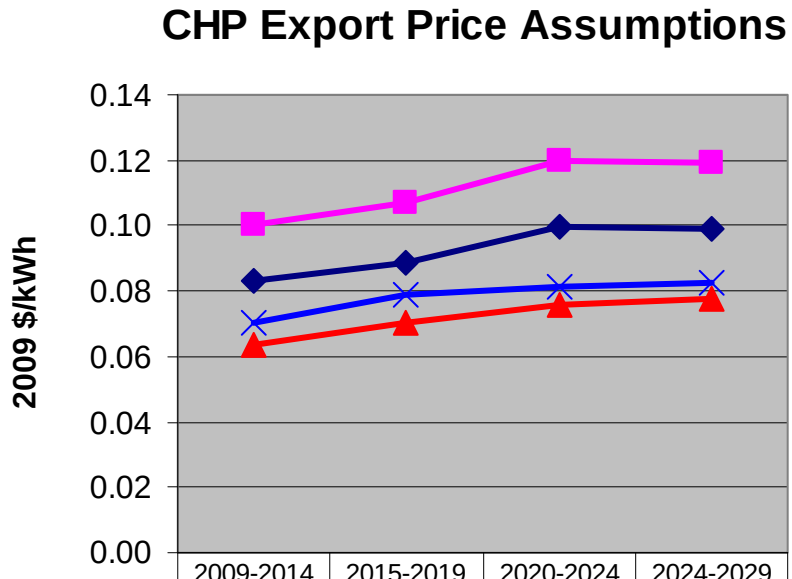
Export Contract Price for Projects Larger Than 20 MW

- A basic contract price for large projects was assumed to be based on the long-term marginal cost of generation determined by the cost of power from a natural gas-fired combined-cycle power plant (shown previously in **Figure 22**).
- An alternative, more aggressive, contract price for large projects was estimated by modifying the assumptions in the 2008 MPR Cost Model. [17] The embedded CPUC gas price forecast was replaced by the gas price forecast used for this study. In addition, the GHG

[17] *2008 MPR Model E4214 Final Publci.xls*, E3, CPUC, 2008.

adders, appropriate for replacing gas-fired generation with 100% renewable sources were removed from the calculation. Escalation was based on the increase in yearly contract prices shown in the model converted to 2009 constant dollars using the EIA GDP price index assumptions from the April 2009 Stimulus Case that was the source for the gas price forecast. By removing the GHG price adders, it is appropriate to consider this contract price in conjunction with a separate payment for actual avoided CO2 emissions.

The five-year price averages for these four price tracks are shown in **Figure 24**.



	2009-2014	2015-2019	2020-2024	2024-2029
SMUD FIT	$0.0833	$0.0889	$0.0998	$0.0992
IOU FIT Est.	$0.1004	$0.1070	$0.1197	$0.1191
Large Contract	$0.0638	$0.0705	$0.0756	$0.0777
Aggressive Contract	$0.0704	$0.0789	$0.0814	$0.0826

Figure 24: CHP Export Price Forecasts

Source: SMUD, ICF International

2.4. CHP Technical Potential

This section provides an estimate of the technical market potential for combined heat and power in the industrial, commercial/institutional, and multi-family residential market sectors in California. The technical potential is an estimation of market size constrained only by technological limits—the ability of CHP technologies to fit customer energy needs. CHP technical potential is calculated in terms of CHP electrical capacity that could be installed at existing and new industrial and commercial facilities based on the estimated electric and thermal needs of the site. The technical market potential does not consider screening for economic rate of return, or other factors such as ability to retrofit, owner interest in applying

CHP, capital availability, natural gas availability, or variation of energy consumption within customer application/size class.

The technical potential is useful in understanding the potential size and distribution of the target CHP market in the region. Identifying the technical market potential is a preliminary step in the assessment of actual economic market size and ultimate market penetration.

CHP is best applied at facilities that have significant and concurrent electric and thermal demands. In the industrial sector, CHP thermal output has traditionally been in the form of steam used for process heating and for space heating. For commercial and institutional users, thermal output has traditionally been steam or hot water for space heating and potable hot water heating. More recently, CHP has included the provision of space cooling through the use of absorption chillers.

Three different types of CHP markets were included in the evaluation of technical potential:

- Traditional power and heat CHP
- Combined cooling, heating and power (CCHP)
- Export of power produced by CHP

These first two markets were further disaggregated by high load factor and low load factor applications resulting in the analysis of five distinct market segments.

Traditional CHP

This market represents CHP applications where the electrical output is used to meet all or a portion of the base load for a facility and the thermal energy is used to provide steam or hot water. The most efficient sizing for CHP is to match thermal output to baseload thermal demand at the site. Depending on the type of facility, the appropriate sizing could be either electric or thermal limited. Industrial facilities often have "excess" thermal load compared to their on-site electric load, which means the CHP system will generate more power than can be used on-site if sized to match the thermal load. Commercial facilities almost always have excess electric load compared to their thermal load. Two sub-categories were considered:

- High load factor applications: This market provides for continuous or nearly continuous operation of the CHP system. It includes all industrial applications and round-the-clock commercial/institutional operations such colleges, hospitals, and prisons.
- Low load factor applications: Some commercial and institutional markets provide an opportunity for coincident electric/thermal loads for a period of 3,500 to 5,000 hours per year. This sector includes applications such as office buildings, health clubs, and laundries.

Combined Cooling Heating and Power (CCHP)

All or a portion of the thermal output of a CHP system can be converted to air conditioning or refrigeration with the addition of a thermally activated cooling system. This type of system can potentially open up the benefits of CHP to facilities that do not have the year-round heating load to support a traditional CHP system. A typical CHP system in these applications would

provide the annual hot water load, a portion of the space heating load in the winter months and a portion of the cooling load during the summer months. Two sub-categories were considered:

- Incremental high load factor applications: These markets represent round-the-clock commercial/institutional facilities such as hospitals, nursing homes, and hotels that could support traditional CHP, but, with consideration of cooling as an output, could support additional CHP capacity while maintaining a high level of utilization of the thermal energy from the CHP system.
- Low load factor applications. These represent markets such as big box retail, restaurants, and food sales that otherwise could not support traditional CHP due to a lack of thermal load.

CHP Export Market

The previous two categories are based on the constraint that all of the thermal and electric energy must be utilized on-site. Within many large industrial process facilities, there is often enough steam demand such that thermally sized CHP systems produce excess electricity above the facilities' internal needs, electricity that could be exported to the wholesale power market. The incremental export potential of electrical power from these facilities was quantified and evaluated as a separate market.

2.4.1. Technical Potential Methodology

The determination of technical market potential consists of the following elements:

- Identify applications where CHP provides a reasonable fit to the electric and thermal needs of the user. Target applications are identified based on reviewing the electric and thermal energy consumption data for various building types and industrial facilities.
- Quantify the number and size distribution of target applications. Various regional data sources are used to identify the number of target application facilities by sector and by size (electric demand) that meet the thermal and electric load requirements for CHP.
- Estimate CHP potential in terms of megawatt (MW) electric capacity. Total CHP potential is derived for each target application based on the number of target facilities in each size category and CHP sizing criteria appropriate for each application sector.
- Subtract existing CHP from the identified sites to determine the remaining technical market potential.

2.4.2. CHP Target Markets

In general, the most efficient and economic CHP operation is achieved when: 1) the system operates at full-load most of the time (high load factor application), 2) the thermal output can be fully utilized by the site, and 3) the recovered heat displaces fuel or electricity purchases.

There are a number of commercial and industrial applications that characteristically have sufficient and coincident thermal and electric loads for CHP. Examples of these applications include food processing, pulp and paper plants, laundries, and health clubs. Most commercial and light industrial applications have low base thermal loads relative to the electric load, but

have high thermal loads in the cooler months for heating. Such applications include hotels, hospitals, nursing homes, college campuses, correctional facilities, and light manufacturing.

In order to identify applications where CHP provides a reasonable fit to the electric and thermal needs of the user, this study reviewed electric and thermal energy (heating and cooling) consumption data for various building types and industrial facilities. Data sources included the DOE EIA *Commercial Buildings Energy Consumption Survey (CBECS),* the DOE *Manufacturing Energy Consumption Survey (MECS),* the *Major Industrial Plant Database (MIPD*), and *Commercial Energy Profile Database (CEPD*)[18], and various market summaries developed by DOE, Gas Technology Institute (GTI), and the American Gas Association. Existing CHP installations in the commercial/institutional and industrial sectors were also reviewed to understand the required profile for CHP applications and to identify target applications.

National level data was analyzed to develop national average electric and thermal demand profiles by application. It is also recognized that regional climate and operating factors can impact both electric and thermal load profiles. This is not as critical an issue for industrial applications because they tend to be more uniform in their operation nationwide than commercial and institutional facilities. Commercial facilities use a high proportion of their purchased energy on heating and cooling, which is highly affected by local weather conditions. Therefore, sources of electric and thermal load data specific to California were also reviewed. The MIPD and CEPD facilities in California were analyzed, along with the existing CHP fleet in California. A key data source for the commercial sector is the *California Commercial End-Use Survey (CEUS),* which was used to further refine the commercial sector's electricity and thermal demand estimates to be more indicative of a California climate.

CHP system sizing for the three markets previously identified is based on matching to appropriate thermal loads:

- Traditional CHP – Size the CHP system for the base thermal load (domestic hot water, pool heating, showers, laundries, kitchens), which usually results in a system sized below the base electric load for commercial facilities. For many industrial facilities, the CHP system is sized to the process steam or hat water load but may be capped by the electric demand at the site (i.e., thermal demand could support a larger CHP system).
- Combined Cooling Heating and Power (CCHP) – Size the CHP system to include thermally activated cooling to create additional thermal use during the cooling months that when combined with space heating justifies a larger CHP system that better matches the electric demand in certain commercial and institutional applications.
- Export CHP – Size the CHP system to meet the entire thermal load at an industrial facility, with excess electricity generation being exported to the grid. The previous two categories are based on the assumption that all of the thermal and electric energy is utilized on-site. Within large industrial process facilities, there is often excess steam demand that could

18 The Major Industrial Plant Database (IMIPD) and Commercial Energy Profile Database (CEPD) are private databases that contain site-specific energy estimates for industrial and commercial facilities. Both are offered by HIS Inc.

support larger CHP systems with significant quantities of electricity that could be exported to the wholesale power system.

Tables 16 and **17** show the CHP market applications classified by these categories as well as their assumed load profiles. Applications with a high load factor were assumed to operate for 7,500 hours a year, whereas applications with a low load factor were assumed to operate for 5,000 hours a year. The category and load profile combinations make up the four markets that were defined at the beginning of this section. Each application is shown with both the corresponding North American Industry Classification System (NAICS) code and Standard Industrial Classification (SIC) code.

Table 16: Traditional CHP Target Applications

NAICS	SIC	Application	Application Type	Load Factor	Export Power Potential
311 - 312	20	Food Processing	Industrial	High	Yes
313	22	Textiles	Industrial	High	Yes
321	24	Lumber and Wood	Industrial	High	Yes
337	25	Furniture	Industrial	High	No
322	26	Paper	Industrial	High	Yes
325	28	Chemicals	Industrial	High	Yes
324	29	Petroleum Refining	Industrial	High	Yes
326	30	Rubber/Misc Plastics	Industrial	High	No
331	33	Primary Metals	Industrial	High	No
332	34	Fabricated Metals	Industrial	High	No
333	35	Machinery/Computer Equip	Industrial	High	No
336	37	Transportation Equip.	Industrial	High	No
335	38	Instruments	Industrial	High	No
339	39	Misc. Manufacturing	Industrial	High	Yes
2213	4941	Water Treatment/Sanitary	Commercial/Institutional	High	No
92214	9223	Prisons	Commercial/Institutional	High	No
8123, 8213	7211	Laundries	Commercial/Institutional	Low	No
71394	7991	Health Clubs	Commercial/Institutional	Low	No
71391	7992	Golf/Country Clubs	Commercial/Institutional	Low	No
8111	7542	Carwashes	Commercial/Institutional	Low	No

Source: ICF International

Table 17: Combined Cooling Heating and Power Target Applications

NAICS	SIC	Application	Application Type	Load Factor
531	6513	Apartments	Commercial/Institutional	High
721	7011	Hotels	Commercial/Institutional	High
623	8051	Nursing Homes	Commercial/Institutional	High
622	8062	Hospitals	Commercial/Institutional	High
6113	8221	Colleges/Universities	Commercial/Institutional	High
518	7374	Data Centers	Commercial/Institutional	High
531	6512	Comm. Office Buildings	Commercial/Institutional	Low
6111	8211	Schools	Commercial/Institutional	Low
612	8412	Museums	Commercial/Institutional	Low
491	43	Post Offices	Commercial/Institutional	Low
452	50	Big Box Retail	Commercial/Institutional	Low
48811	4581	Airport Facilities	Commercial/Institutional	Low
445	5411	Food Sales	Commercial/Institutional	Low
722	5812	Restaurants	Commercial/Institutional	Low
512131	7832	Movie Theaters	Commercial/Institutional	Low
92	9100	Government Buildings	Commercial/Institutional	Low

Source: ICF International

2.4.3. California Target CHP Facilities

Various commercial and industrial facility databases were used to identify the number of target application facilities in California by sector and by size (electric demand) that meet the thermal and electric load requirements for CHP. The primary data source to identify potential targets for CHP installations in California was the Dunn & Bradstreet (D&B) *Selectory* Database. The D&B *Selectory* Database contains information on the majority of businesses throughout the country and can be sorted to provide a listing of industrial and commercial facilities in a specific region. This analysis used a set of data consisting of facilities in California that have more than five employees and are in the target applications specified above. The site data includes information on:

- Company name
- Facility location (street address, county, latitude/longitude)
- Line of business (primary SIC code and primary NAICS code)
- Number of employees (at total company and at individual site)
- Annual sales
- Contact information

More than 64,000 sites from the D&B *Selectory* database, including 22,571 industrial sites and 41,882 commercial sites, were screened for CHP potential in this study. Industrial facilities from the *Major Industrial Plant Database* (MIPD) were also used to supplement the D&B *Selectory* list in the large industrial market segment. The MIPD contains detailed information on the

electricity use and boiler fuel use profiles of 4,964 industrial facilities in California. These two data sources were combined by matching the site names and locations and directly using the MIPD energy data where there was a match. This process resulted in about 100 of the largest industrial plants in the state using detailed electric and steam data from MIPD. The largest 40 industrial plants in the combined list were also independently checked to corroborate the electric and boiler fuel data contained in MIPD and the estimated values calculated through the methodology detailed below. Special attention was also paid to the large refineries to make sure that the estimates for additional CHP potential were consistent with current refining industry assumptions.

2.4.4. Quantify Electric and Thermal Loads for CHP Target Applications

In order to estimate the total technical potential for CHP in California, each of the target facilities needs to have a hypothetical CHP system sized to its electrical and thermal loads. The sum of all the individual CHP system capacities would then result in the overall total CHP potential for the state.

Electric Load Estimation

The electric requirements for each of the approximately 64,000 facilities in California were estimated based on either electricity consumption factors applied to the number of employees for each site identified through the D&B databases, or the specific electric consumption estimates for sites identified through MIPD. To estimate the electric consumption based on number of employees, an algorithm was used to assign an annual kWh consumption figure per employee for each NAICS code. This algorithm, originally developed for a previous national market assessment of distributed energy potential, was modified to reflect California-specific conditions based on information contained in the California Commercial End-Use Survey (CEUS) and the California Energy Consumption Data Managements System (ECDMS).

The national level electricity consumption per employee estimates were developed from several sources. For mining industry NAICS codes, total annual electricity consumption and total number of employees by six-digit NAICS code were obtained from the 2002 Census of Mining.[19] For manufacturing industry NAICS codes, total annual electricity consumption and total number of employees by six-digit NAICS code were obtained from the 2002 Census of Manufacturing.[20] Industrial facility NAICS codes were further modified by the percent of energy used for HVAC uses by three-digit NAICS code from EIA's Manufacturing Energy Consumption Survey (MECS).[21]

For the commercial NAICS codes, a private dataset, the D&B Sales & Marketing Solutions' 2003 MarketPlace database, was utilized. The MarketPlace database included estimates of total annual electricity consumption and number of employees by four-digit SIC code for most of the commercial sector. (These four-digit SIC codes were converted to three-, four-, and six-digit NAICS codes.) This data was used to assign kWh per employee estimates for each application.

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19 2002 US Census of Mining: http://www.census.gov/econ/census02/guide/INDRPT21.HTM
20 2002 US Census of Manufacturing: http://www.census.gov/econ/census02/guide/INDRPT31.HTM
21 EIA MECS: http://www.eia.doe.gov/emeu/mecs/contents.html

For NAICS codes for which data was not available, appropriate kWh per employee estimates were assigned based on information from similar applications. Although the MarketPlace database was the primary data source, a number of other sources were used as control totals to refine the estimates from MarketPlace to ensure they were consistent with other industry estimates. The other sources included 1) a small subset of the IHS CEPD data which was previously purchased by the project team, 2) EIA's CBECS data, and 3) EIA's Annual Energy Outlook.[22]

These national industrial and commercial electricity factors were modified to reflect California-specific estimates. The modifications took into account California's weather conditions as well as its unique industrial and commercial application mix. Adjustments were made based on comparing the national level estimates with control totals of California industrial and commercial energy use provided by California's Energy Consumption Data Management System (ECDMS).[23] Tables showing the final kWh per employee factors for California are provided in **Appendix B**.

The average electric demand of each facility in the dataset was estimated by dividing the total kWh electricity consumption for the site by the assumed operating hours corresponding with the application's load factor (7,500 hours a year for high load factor, 5,000 hours a year for low load factor). Given the 64,000 facilities in California that were screened for CHP potential, close to half were dropped from the analysis due to estimated electric demands that were below viable CHP economics. This assessment required a minimum electric demand of 50 kW for a site to be included in the technical potential. After screening for this minimum electric demand, only about 36,000 sites remained as potential CHP candidates. **Table 18** shows how the total sites were screened down to the number that is included in the CHP market assessment.

Table 18: Breakdown of California Facilities Included in Market Assessment

	Industrial	Commercial	Total
Total Sites Considered	22,571	41,882	64,453
Sites Below 50 kW	14,855	13,646	28,501
Total Sites with CHP Technical Potential	7,716	28,236	35,952

Source: ICF International

Thermal Load Estimation

As described earlier, this assessment assumes that the CHP systems would be sized to meet the base thermal loads (heating and cooling) of each site unless the CHP system size exceeded the facility's average electric demand. In this case, the CHP system size would be limited to the site's average electric demand. Estimation of the thermal load is important to properly size the CHP system for high thermal utilization and to determine whether the thermal load would limit the CHP system size. In previous studies, the ICF study team used information on thermal loads for the target CHP applications derived from data in DOE's *Commercial Buildings Energy*

22 AEO 2007 Reference Case: http://www.eia.doe.gov/oiaf/aeo/index.html
23 Energy Consumption Data Management System (ECDMS). http://ecdms.energy.ca.gov/

Consumption Survey (CBECS), and *Manufacturing Energy Consumption Survey (MECS)*, the *Major Industrial Plant Database (MIPD*), and *Commercial Energy Profile Database (CEPD*), as well as studies of industrial electric and thermal profiles developed by DOE, Gas Technology Institute (GTI), and the American Gas Association. These data sources provided sufficient information on the end-use energy consumption in commercial and industrial facilities such that average power-to-heat ratio factors for each target application could be developed. Application specific power-to-heat ratios are applied to the electricity consumption estimates developed for each potential CHP target site to quantify the thermal load at each site.

National level data gives a national average power-to-heat ratio by application rate and does not account for regional factors. This is not a critical issue for industrial applications because most of the thermal use by industrial facilities goes to process demands and is not as greatly impacted by local conditions. However, commercial facilities use a high proportion of their thermal energy on heating and cooling, which is highly affected by local weather conditions. Therefore, sources of electric and thermal load data specific to California businesses were also reviewed. The MIPD and CEPD data for California were analyzed, along with the existing CHP fleet in California. A key data source for the commercial sector is the California Commercial End-Use Survey (CEUS)[24], which was used to modify the commercial application power-to-heat ratios to be more indicative of a California climate. CEUS is a survey of commercial sector energy use that captures detailed building systems data, electricity and gas usage, thermal shell characteristics, equipment inventories, operating schedules, and other commercial building characteristics. The survey covered approximately 2,800 commercial facilities located within the service areas of PG&E, SDG&E, SCE, Southern California Gas Company and SMUD. Specialized software used the survey data to create end-use load profiles and electricity and natural gas consumption estimates by end use for commercial market segments. CEUS provides energy intensity data on the amount of electricity and natural gas that commercial facilities use per square foot of building space by end use. CEUS includes detailed data on the electric and natural gas usage patterns for:

- Small office buildings
- Large office buildings
- Restaurants
- Retail establishments
- Food stores
- Refrigerated warehouses
- Unrefrigerated warehouses
- Schools
- Colleges
- Health care facilities
- Lodging

24 *California Commercial End-Use Survey* (CEUS). http://www.energy.ca.gov/ceus/

Industrial Applications

The Major Industrial Plant Database (MIPD)[25] contains information on electric demand and steam draw for more than 15,000 industrial sites in the United States. This data was analyzed for each industry for plants across the United States and then separately for plants in California to identify any regional differences that may be present. Data on industrial thermal loads were also taken from a combination of the Manufacturing Energy Consumption Survey (MECS)[26] and the Energy and Environmental Analysis Industrial Database. The sector-specific power-to-heat ratios from all of these sources are compared in **Table 19**, and were used to estimate typical industrial thermal loads for each industrial target application. These power-to-heat ratios were tested with California electric customer data to see which ratios came closest to matching the electric load data with known control totals for thermal loads as provided by California's Energy Consumption Data Management System (ECDMS).[27]

Table 19: Industrial Power-to-Heat Ratios from Various Data Sources

NAICS	SIC	CA MIPD P/H Ratio	All Sites MIPD P/H Ratio	MECS/EEA P/H Ratio	Final Analysis P/H Ratio
311 - 312	20	0.53	0.54	0.59	0.59
313	22	0.33	0.80	0.84	0.84
321	24	0.23	0.50	0.24	0.24
337	25	0.80	1.04	1.45	1.45
322	26	0.22	0.21	0.27	0.27
511	27	0.92	1.07	10.76	1.07
325	28	0.40	0.33	0.50	0.50
324	29	0.28	0.26	0.26	0.26
326	30	0.73	1.09	2.12	2.12
327	32	0.24	0.29	4.36	0.29
331	33	1.28	1.07	6.63	1.85
332	34	0.59	1.06	1.96	1.96
333	35	2.27	0.66	3.04	3.00
336	37	1.49	0.93	1.48	1.48
335	38	4.37	0.62	2.49	2.49
339	39	10.33	0.44	0.48	0.48

Source: Major Industrial Plant Database, Manufacturer's Energy Consumption Survey

The power-to-heat ratios referenced in **Table 19** were used for all industrial sites in the data list except for those with specific electric and thermal information from MIPD. This exception mainly affected the largest 40 industrial plants.

Commercial Applications

A number of California-specific sources containing typical commercial electric and thermal loads were evaluated in this assessment. CEUS electric and natural gas usage data by end use

25 IHS Inc. Major Industrial Plant Database (MIPD). http://energy.ihs.com/Products/Mipd/
26 Energy Information Administration. Manufacturing Energy Consumption Survey. http://www.eia.doe.gov/emeu/mecs/
27 Energy Consumption Data Management System (ECDMS). http://ecdms.energy.ca.gov/

was utilized to identify the power-to-heat ratio of target CHP commercial applications. The end-use breakdown identified the thermal loads that could be displaced with CHP. **Table 20** shows the electric and natural gas intensity data for the relevant commercial applications and end uses from the CEUS database. All electric loads, except for heating and water heating, were assumed to contribute to the electric portion of the power-to-heat ratio. The heating and water heating from both electric and natural gas (as well as the process natural gas use) were used to estimate the applicable heating-only thermal load for each application (assuming a boiler conversion efficiency of 80%). The electricity used for cooling was converted into an estimate of the thermal energy that would be required to provide this amount of cooling based on an electric chiller energy consumption of 1 kWh/ton of cooling and a single-stage absorption chiller coefficient of performance (COP) of 0.7.

Table 20: CEUS Commercial Application Energy Data

Application	Total Electric, kWh/sq ft	Cooling Electric, kWh/sq ft	Hot Water, kWh/sq ft	Space Heating, kWh/sq ft	Process Heat, kWh/sq ft	Total Heating, kWh/sq ft	Cooling Demand, Tons	Thermal Required for Cooling, kWh/sq ft
Colleges	11.38	2.92	2.59	6.58	0.25	7.34	2.92	14.67
School	7.23	1.20	1.48	3.06	0.04	3.63	1.20	6.03
Food Sales	40.50	2.88	2.38	2.87	0.03	4.20	2.88	14.47
Restaurant	39.80	5.76	14.63	2.33	0.10	13.57	5.76	28.94
Health	18.82	4.42	9.27	10.29	2.00	15.65	4.42	22.21
Lodging	11.67	2.43	8.52	2.55	0.50	8.86	2.43	12.21
Retail	13.85	2.21	0.37	0.97	0.08	1.07	2.21	11.10
Small Office Building	12.65	2.61	0.74	2.73	0.04	2.78	2.61	13.11
Large Office Building	17.10	3.73	0.98	5.54	0.39	5.22	3.73	18.74
Refrigerated Warehouses	19.97	13.44	0.26	0.26	0.08	0.42	13.44	67.53
Unrefrigerated Warehouses	4.38	0.33	0.14	0.79	0.02	0.74	0.33	1.66
Misc	9.61	1.20	2.90	2.10	1.50	4.00	1.20	6.03

Source: California Commercial End-Use Survey

Overall, the CEUS data were used to refine the final commercial power-to-heat ratios that were used in the market assessment. **Table 21** shows how the heating-only, power-to-heat ratios developed from CEUS data compared to heating-only ratios developed from EIA's Commercial Building Energy Consumption Survey (CBECS)[28], and other sources of commercial electric and thermal data. The final power-to-heat ratios for each commercial application are based on the CHOP system supplying both heating and cooling loads. However, unlike the industrial thermal load estimation, a commercial CHP system was not assumed to achieve 100% thermal utilization. Experience with commercial CHP installations shows that due to operating

28 Energy Information Administration. Commercial Energy Consumption Survey (CBECS). http://www.eia.doe.gov/emeu/cbecs/

schedules, site constraints, and the nature of the heating and cooling loads themselves, commercial CHP systems are typically able to address 70-80% of heating loads and only about 50-60% of site cooling loads. The final commercial power-to-heat ratios used for the analysis are based on supplying 80% of the hot water and space heating loads, and 60% of the cooling loads in each application.

Table 21: Commercial Power-to-Heat Ratio Estimates

	CBECS P/H Ratio*	CEC CEUS P/H Ratio*	Other Sources P/H Ratio*	Final Analysis P/H Ratio**
Principal Building Activity				
Colleges	0.81	1.55	0.67	0.78
Education	0.81	1.99	0.67	1.11
Food Sales	3.90	9.64	5.93	3.36
Food Service	0.76	2.93	2.47	1.47
Health Care	0.80	1.20	0.9	0.73
Lodging	0.75	1.32	0.82	0.81
Retail	1.78	12.92	1.33	1.84
Office	1.64	3.28	2.3	1.11
Public Assembly	0.80	n.a.	0.72	0.9
Public Order and Safety	0.80	n.a.	0.89	0.5
Service	1.09	12.92	n.a	1.84
Warehouse and Storage (refrigerated)	1.29	5.89	1.45	0.5
Other	0.96	2.40	1.18	1.41

*P/H ratiops based on heating load only

** P/H ratios based on 80% heating load and 60% cooling load

Sources: EIA Commercial Buildings Energy Consumption Survey 2003, CEUS, ICF

CHP System Sizing

The electric and thermal data described above were used to develop thermal factors for each application that is used to estimate the CHP system size for each potential site as a function of average electric demand. The thermal factor is based on both the power-to-heat ratio (P/H) of the application as well as the P/H ratio of a typical CHP system for that application in the following relationship:

$$\text{Thermal Factor} = \frac{\text{P/H (CHP system)}}{\text{P/H (target application)}}$$

The thermal factor is multiplied by the average electric demand to determine the estimated CHP system size for each site.

$$\text{CHP System Size} = \text{Site Average Electric Demand} \times \text{Thermal Factor}$$

A thermal factor of one would result in the CHP system capacity being equal to the average electric demand of the facility. A thermal factor less than one would indicate that the application is thermally limited and the resulting CHP system size would be below the average electric demand of the facility. A thermal factor greater than one indicates that a CHP system sized to the thermal load would produce more electricity than can be used on-site, resulting in

excess power that could be exported to the grid. **Table 22** and **Table 23** present the thermal factors used in the analysis for industrial and commercial applications by size range. A number of industrial applications have thermal factors greater than one, indicating the capacity to export power to the grid for CHP systems sized to meet thermal loads.

Table 22: Industrial Thermal Factors

Application	<1 MW	1 - 5 MW	5 - 20 MW	>20 MW
Food Processing	1.10	1.10	1.69	2.03
Textiles	0.77	0.77	1.18	1.42
Wood Products	2.72	2.72	4.18	5.02
Furniture	0.45	0.45	0.69	0.83
Paper	2.37	2.37	3.64	4.37
Printing	0.60	0.60	0.93	1.12
Chemicals	1.29	1.29	1.98	2.38
Refining	2.52	2.52	3.88	4.66
Plastics and Rubber	0.31	0.31	0.47	0.57
Primary Metals	0.25	0.25	0.50	0.65
Fabricated Metals	0.33	0.33	0.51	0.61
Machinery	0.21	0.21	0.33	0.40
Transportation Equipment	0.44	0.44	0.67	0.81
Instruments	0.26	0.26	0.40	0.48
Misc Manufacturing	1.34	1.34	2.06	2.48

Source: ICF International

Table 23: Commercial Thermal Factors

Application	<1 MW	1 - 5 MW	5 - 20 MW	>20 MW
Water Treatment/Sanitary	0.50	0.59	0.74	0.88
Laundries	1.00	1.00	1.00	1.00
Carwashes	1.00	1.00	1.00	1.00
Health Clubs	0.80	0.94	1.00	1.00
Golf/Country Clubs	0.80	0.94	1.00	1.00
Schools	0.62	0.73	0.91	1.00
Colleges/Universities	0.88	1.00	1.00	1.00
Prisons	0.45	0.53	0.66	0.79
Hotels	0.84	1.00	1.00	1.00
Nursing Homes	0.84	1.00	1.00	1.00
Hospitals	0.94	1.00	1.00	1.00
Apartments	0.84	1.00	1.00	1.00
Museums	0.62	0.73	0.91	1.09
Warehouses	1.00	1.00	1.00	1.00
Food Sales	0.20	0.24	0.29	0.35
Restaurants	0.48	0.56	0.71	0.85
Post Offices	0.54	0.64	0.79	0.95
Airports	0.62	0.73	0.91	1.00
Big Box Retail	0.37	0.44	0.54	0.65
Movie Theaters	0.37	0.44	0.54	0.65
Office Buildings	0.62	0.73	0.91	1.00
Data Centers	1.00	1.00	1.00	1.00

Source: ICF International

The thermal factors vary by size range due to differences in CHP system power-to-heat (P/H) ratios based on the characteristics of typical prime mover technologies used for each size range. The CHP systems below 5 MW were assumed to be reciprocating engines; above 5 MW, they were assumed to be gas turbines. As CHP technologies increase in size, their P/H ratios also tend to increase as electrical efficiency improves and heat available for recovery decreases. The assumed CHP system P/H ratios by size range are shown in **Table 24**.

Table 24: CHP System Power-to-Heat Ratio by Size Range

CHP Technology	<1 MW	1 - 5 MW	5 - 20 MW	>20 MW
P/H Ratio	0.68	0.80	1.00	1.20

Source: ICF International

After a potential CHP capacity was determined for each of the potential sites, the existing CHP installations in California were matched to the list and subtracted from the CHP technical potential. If a site with an existing CHP system had a higher amount of technical potential than is currently installed, the difference was considered to be the remaining potential at the site.

2.4.5. Technical Potential Results

Estimates for CHP technical market potential were developed using the methodology described above for both 2009 and 2029. This section profiles the CHP technical potential estimates by application and size range for the entire state and for each utility. The estimates are divided into the CHP technical potential that serves on-site electric demands at target facilities and additional CHP technical potential that is available if the facilities are allowed to export electricity to the grid (export capacity). Accordingly, the "on-site" tables do not include any CHP capacity that is over the facility average electric demand. Excess CHP capacity that is available in certain applications is presented in the export tables.

The total technical market potential (on-site and export) for CHP equals 16,071 MW in 2009 for potential at existing commercial and industrial facilities with another 2,346 MW expected from new or expanded commercial and industrial facilities during the forecast period, for a total of more than 18,000 MW in 2029.

Technical Potential—2009

Table 25, **Table 26**, **Table 27**, **Table 28**, and **Table 29** summarize the current (2009) technical potential estimates by application, size, and utility territory. The technical potential for CHP is highest in industrial sectors that currently have a large amount of existing CHP installations, such as chemicals, food processing, and paper production. However, because many of the very large industrial facilities in California already have CHP systems, the majority of the potential now falls in the mid-range system sizes between 1 MW and 20 MW.

Table 25: On-Site CHP Technical Potential at Existing Industrial Facilities in 2009

SICs	Application	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW	Total MW
20	Food	256	141	336	105	56	894
22	Textiles	52	17	42	16	0	127
24	Lumber and Wood	64	16	57	8	0	146
25	Furniture	5	1	0	0	0	5
26	Paper	87	58	162	200	29	536
27	Printing	11	8	5	5	0	29
28	Chemicals	200	158	546	485	0	1,389
29	Petroleum Refining	11	10	85	63	123	293
30	Rubber/Misc Plastics	71	22	29	0	0	122
32	Stone/Clay/Glass	7	5	22	27	0	61
33	Primary Metals	38	18	42	44	0	142
34	Fabricated Metals	49	13	15	0	0	78
35	Machinery/Computer Equip.	29	3	20	0	0	52
37	Transportation Equip.	40	19	29	83	36	206
38	Instruments	33	9	15	5	0	63
39	Misc. Manufacturing	10	2	0	0	0	12
	Total	**966**	**501**	**1,403**	**1,042**	**245**	**4,157**

Source: ICF International

Commercial facility CHP potential is heavily concentrated in the size ranges below 5 MW, where almost 80% of the technical potential lies. This potential is boosted by several large applications that incorporate cooling into the CHP system design, including college/universities, commercial buildings, government buildings, schools, and hotels.

Table 26: On-Site CHP Technical Potential at Existing Commercial Facilities in 2009

SICs	Application	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW	Total MW
43	Post Offices	7	2	0	0	0	9
52	Big Box Retail	322	32	16	0	0	370
4222	Warehouses	16	3	0	0	0	19
4581	Airports	3	1	0	15	0	20
4941	Water Treatment/Sanitary	25	7	7	0	0	39
5411	Food Sales	256	8	4	10	0	277
5812	Restaurants	453	14	9	9	0	485
6512	Commercial Buildings	488	363	491	0	0	1,342
6513	Apartments	150	108	68	0	0	326
7011	Hotels	219	78	175	39	0	512
7211	Laundries	29	6	3	0	0	38
7374	Data Centers	23	9	9	0	0	42
7542	Carwashes	13	1	0	0	0	13
7832	Movie Theaters	2	0	1	0	0	3
7991	Health Clubs	3	1	1	0	0	4
7992	Golf/Country Clubs	57	1	2	15	0	74
8051	Nursing Homes	123	4	8	6	0	140
8062	Hospitals	70	70	303	38	0	482
8211	Schools	526	15	34	11	0	586
8221	Colleges/Universities	140	104	427	630	563	1,864
8412	Museums	10	1	0	0	0	11
9100	Government Buildings	213	58	191	148	41	651
9223	Prisons	12	7	43	0	0	62
	Total	**3,159**	**893**	**1,792**	**922**	**604**	**7,371**

Source: ICF International

The estimate of the CHP export market is based primarily on the excess power capacity at the largest 100 industrial facilities in the state, characterized in terms of steam demand. Most of this potential comes from a handful of very large refineries, chemical plants, and food processors. The estimate of technical potential for additional export CHP capacity in enhanced oil recovery applications is based on a 1999 EPRI analysis of the potential at 10 existing oil fields and the degree of market saturation that already exists for CHP.[29] There is a total technical CHP export potential of 4,544 MW. Export potential is geographically located in this study for placement in utility service territories; however facilities that export power have the freedom to sell their electricity to any entity they wish, including those outside their geographic area.

29 *Enhanced Oil Recovery Scoping Study*, EPRI, Palo Alto, CA: 1999. TR-113836.

Table 27: Export CHP Technical Potential at Existing Industrial Facilities in 2009

SICs	Application	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW	Total MW
13	Enhanced Oil Recovery	0	0	0	0	1,070	1,070
20	Food	9	16	36	4	282	347
22	Textiles	0	0	0	3	0	3
24	Lumber and Wood	49	21	61	94	68	292
25	Furniture	0	0	0	0	0	0
26	Paper	6	22	67	134	699	928
27	Printing	0	0	0	0	0	0
28	Chemicals	3	39	83	168	456	750
29	Petroleum Refining	1	6	2	150	934	1,093
30	Rubber/Misc Plastics	0	0	0	0	0	0
32	Stone/Clay/Glass	1	2	13	19	20	55
33	Primary Metals	0	0	0	0	0	0
34	Fabricated Metals	0	0	0	0	0	0
35	Machinery/Computer Equip.	0	0	0	0	0	0
37	Transportation Equip.	0	0	0	0	0	0
38	Instruments	0	0	0	0	0	0
39	Misc. Manufacturing	3	4	0	0	0	7
Total		**71**	**110**	**261**	**571**	**3,530**	**4,544**

Source: ICF International

The total technical potential for CHP in California for 2009 is summarized by CHP market sector in **Table 28**. It indicates that there is more remaining potential in commercial facilities than in industrial facilities, which is a departure from the traditional characterization of CHP target markets. There is also a heavy concentration of potential in the small-size ranges, indicating that many large facilities already have CHP systems for their on-site needs, leaving the remaining large-size CHP potential in the export market.

Table 28: Total CHP Technical Potential at Existing Facilities – Commercial and Industrial – in 2009 by CHP Market Sector

Market Type	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW	Total MW
Industrial On-site	966	501	1,403	1,042	245	4,157
Commercial Traditional	297	133	124	15	0	568
Commercial Heating & Cooling	2,862	760	1,668	907	604	6,802
Export Existing	71	110	261	571	3,530	4,544
Total	**4,197**	**1,504**	**3,456**	**2,535**	**4,379**	**16,071**

Source: ICF International

Table 29 summarizes the current technical potential by utility area. The utility with the largest amount of CHP technical potential is PG&E; Southern California Edison (SCE) is a very close second. Since PG&E also has the largest amount of existing CHP installations, the remaining CHP potential indicates that SCE has more room for growth in CHP capacity as a percentage of current CHP installations. The Los Angeles Department of Water and Power (LADWP) also has a significant amount of remaining potential given the small size of its service area.

Table 29: Total CHP Technical Potential at Existing Facilities – Commercial and Industrial – in 2009 by Utility Territory

Utility	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW	Total
LADWP	191	89	187	111	523	1,100
Other North	77	26	52	63	106	325
Other South	175	55	136	99	0	465
PG&E	1,460	520	1,361	904	2,467	6,712
SCE	1,808	636	1,339	1,051	1,143	5,976
SDG&E	367	132	273	203	93	1,067
SMUD	119	47	109	104	47	426
Total	**4,197**	**1,504**	**3,456**	**2,535**	**4,379**	**16,071**

Source: ICF International

Technical Potential Growth Between 2009 and 2029

While the 2009 technical potential estimate is based on the facility data in the potential CHP site list, the 2029 estimate includes economic growth projections for target applications between 2009 and 2029. In order to estimate the development of new commercial and industrial facilities and expansion in existing facilities between the present and 2029, economic projections for growth by target market applications in California were reviewed. The growth factors used in the analysis for growth between 2009 and 2029 by individual sector are shown below. These growth projections were derived from data in the EIA's Annual Energy Outlook 2009 stimulus case. The growth rates were used in this analysis as an estimate of the growth in new facilities or expansion at existing facilities. In cases where an economic sector is declining, it was assumed that no new facilities or expanded capacity at existing facilities would be added to the technical potential for CHP.

Table 30: Industrial Application Growth Projections

Application	2008-2029 Growth Rate, %
Food	33.80
Textiles	0.00
Lumber and Wood	35.5
Furniture	6.29
Paper	7.91
Publishing	0.00
Chemicals	0.00
Petroleum Refining	0.00
Rubber / Misc Plastics	0.00
Stone/Clay/Glass	0.00
Primary Metals	0.00
Fabricated Metals	0.00
Machinery/Computer Equip.	11.90
Transportation Equip.	11.36
Instruments	12.52
Misc. Manufacturing	33.97

Source: EIA 2009 Annual Energy Outlook, Stimulus Case

Table 31: Commercial Application Growth Projections

Application	2008-2029 Growth Rate, %
Post Offices	13.65
Big Box Retail	15.20
Warehouses	25.67
Airport Facilities	25.67
Wastewater Treatment/Sanitary	14.40
Food Stores	27.96
Restaurants	15.20
Commercial Office Buildings	27.30
Apartments	8.62
Hotels	25.67
Laundries	25.67
Data Centers	27.30
Car Washes	27.30
Movie Theaters	32.46
Health Clubs	27.30
Golf/Country Clubs	25.67
Nursing Homes	35.81
Hospitals	35.81
Schools	19.82
Colleges/Universities	19.82
Museums	15.32
Government Buildings	13.60
Prisons	25.67

Source: EIA 2009 Annual Energy Outlook, Stimulus Case

Table 32 and **Table 33** show the additional CHP technical market potential due to projected economic growth in California over the time period of the analysis.

Table 32: Total CHP Technical Potential Growth Between 2009 and 2029 by CHP Market Sector

Market Type	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW	Total MW
Industrial Onsite	132	62	154	64	25	438
Commercial Traditional	47	15	19	4	0	85
Commercial Heating & Cooling	622	190	416	181	117	1,526
Export New Facilities	22	16	39	45	175	297
Total	**823**	**283**	**628**	**294**	**317**	**2,346**

Source: ICF International

Table 33: CHP Technical Potential Growth Between 2009 and 2029 by Utility Territory

Utility	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW	Total MW
LADWP	37	17	33	22	55	163
Other North	17	7	13	14	24	75
Other South	32	9	24	10	0	74
PG&E	302	107	276	121	128	932
SCE	342	111	218	96	84	851
SDG&E	70	22	45	17	17	172
SMUD	24	10	20	15	9	78
Total	**823**	**283**	**628**	**294**	**317**	**2,346**

Source: ICF International

The total technical potential for CHP in 2029 is the summation of the 2009 technical potential and the growth in CHP potential between 2009 and 2029. The tables below summarize the total technical potential for CHP in 2029.

Table 34: Total Industrial CHP Technical Potential in 2029

SICs	Application	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW	Total MW
20	Food	343	188	449	140	75	1,196
22	Textiles	52	17	42	16	0	127
24	Lumber and Wood	87	22	77	11	0	197
25	Furniture	5	1	0	0	0	6
26	Paper	94	63	175	216	32	579
27	Printing	11	8	5	5	0	29
28	Chemicals	200	158	546	485	0	1,389
29	Petroleum Refining	11	10	85	63	123	293
30	Rubber/Misc Plastics	71	22	29	0	0	122
32	Stone/Clay/Glass	7	5	22	27	0	61
33	Primary Metals	38	18	42	44	0	142
34	Fabricated Metals	49	13	15	0	0	78
35	Machinery/Computer Equip.	33	4	22	0	0	58
37	Transportation Equip.	45	21	32	92	41	230
38	Instruments	38	10	17	6	0	70
39	Misc. Manufacturing	14	3	0	0	0	16
	Total	**1,098**	**563**	**1,557**	**1,106**	**270**	**4,595**

Source: ICF International

Table 35: Total Commercial CHP Technical Potential in 2029

SICs	Application	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW	Total MW
43	Post Offices	8	2	0	0	0	11
52	Big Box Retail	371	37	18	0	0	426
4222	Warehouses	20	4	0	0	0	24
4581	Airports	4	1	0	19	0	25
4941	Water Treatment/Sanitary	28	9	9	0	0	45
5411	Food Sales	328	10	5	12	0	355
5812	Restaurants	522	16	10	10	0	559
6512	Commercial Buildings	621	462	625	0	0	1,708
6513	Apartments	162	117	74	0	0	354
7011	Hotels	275	98	221	50	0	644
7211	Laundries	36	8	3	0	0	47
7374	Data Centers	29	12	12	0	0	53
7542	Carwashes	16	1	0	0	0	17
7832	Movie Theaters	2	0	2	0	0	4
7991	Health Clubs	3	1	1	0	0	6
7992	Golf/Country Clubs	72	1	2	18	0	93
8051	Nursing Homes	167	5	10	8	0	190
8062	Hospitals	96	95	412	52	0	654
8211	Schools	630	18	41	14	0	702
8221	Colleges/Universities	168	125	511	755	675	2,233
8412	Museums	11	1	0	0	0	13
9100	Government Buildings	242	66	217	169	47	740
9223	Prisons	15	9	54	0	0	78
	Total	**3,828**	**1,098**	**2,227**	**1,107**	**722**	**8,981**

Source: ICF International

Table 36: Total Export CHP Technical Potential in 2029

SICs	Application	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW	Total MW
13	Enhanced Oil Recovery	0	0	0	0	1,070	1,070
20	Food	12	22	48	5	378	464
22	Textiles	0	0	0	3	0	3
24	Lumber and Wood	66	28	83	127	92	396
25	Furniture	0	0	0	0	0	0
26	Paper	6	24	72	144	755	1,001
27	Printing	0	0	0	0	0	0
28	Chemicals	3	39	83	168	456	750
29	Petroleum Refining	1	6	2	150	934	1,093
30	Rubber/Misc Plastics	0	0	0	0	0	0
32	Stone/Clay/Glass	1	2	13	19	20	55
33	Primary Metals	0	0	0	0	0	0
34	Fabricated Metals	0	0	0	0	0	0
35	Machinery/Computer Equip.	0	0	0	0	0	0
37	Transportation Equip.	0	0	0	0	0	0
38	Instruments	0	0	0	0	0	0
39	Misc. Manufacturing	5	5	0	0	0	9
	Total	93	126	300	616	3,705	4,841

Source: ICF International

Table 37 profiles the total technical potential for CHP in 2029 by utility territory.

Table 37: Total CHP Technical Potential in 2029 by Utility Territory

Utility	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW	Total MW
LADWP	227	106	220	133	577	1,263
Other North	94	33	65	78	131	400
Other South	207	64	159	109	0	539
PG&E	1,761	627	1,637	1,024	2,595	7,644
SCE	2,150	747	1,557	1,147	1,227	6,828
SDG&E	437	154	318	220	110	1,238
SMUD	143	57	129	119	56	504
Total	**5,020**	**1,787**	**4,084**	**2,829**	**4,697**	**18,417**

Source: ICF International

Figure 25 profiles existing CHP capacity and remaining CHP potential (through 2029) by utility service area. The most significant regions for growth are in the PG&E and SCE service territories.

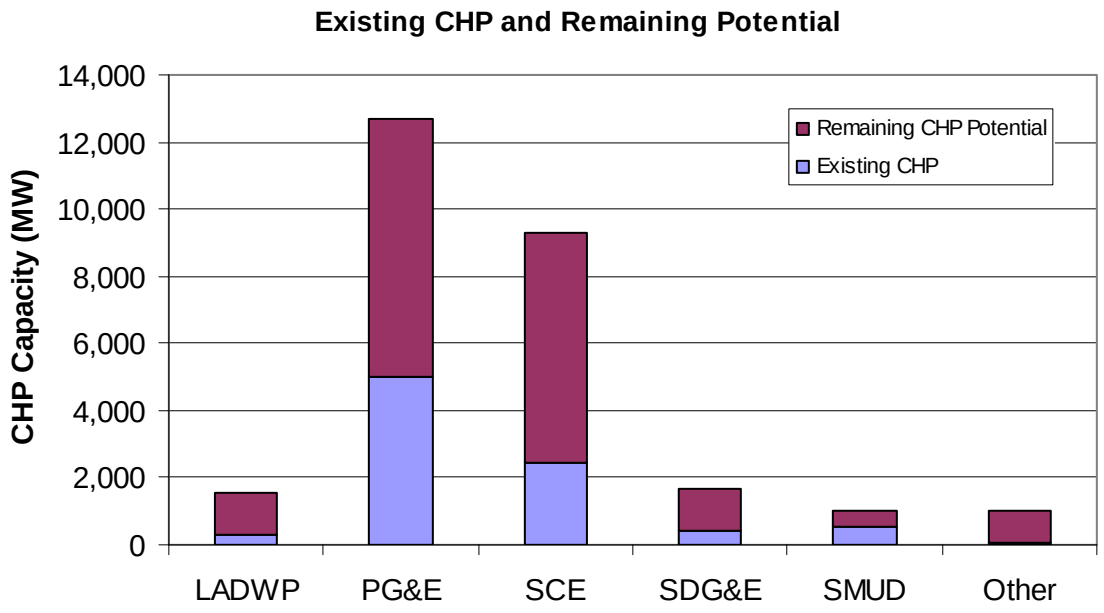


Figure 25: Existing CHP and Total Remaining CHP Potential by Utility Territory

Source: ICF International

Competitive Outlook for CHP

The outlook for CHP market penetration in California will depend on a number of factors:

- The relationship of delivered natural gas and electricity prices, or spark spread.
- The cost and performance of the CHP equipment suitable for use at a given facility.
- The electric and thermal load characteristics of commercial, industrial, and institutional facilities in the state (described in the previous section).
- Incentive payments, if any, to the CHP user that reflect societal or utility benefits of CHP (a number of which will be evaluated as part of this market assessment).
- Customer decisions about the economic value that will trigger investment in CHP or the willingness to consider CHP.

The CHP Market Model considers these factors to estimate forecasted CHP market penetration between 2009 and 2029.

2.5. CHP Market Model

The ICF CHP Market Model estimates cumulative CHP market penetration as a function of the competing CHP system specifications, current and future energy prices, and site electric and thermal load characteristics. The ICF CHP Market Model features are summarized in **Table 38**.

Table 38: ICF CHP Market Model

Forecast Periods	2014, 2019, 2024, 2029
Market Segmentation: Application	High Load Factor
	Low Load Factor
	High Load Factor with Cooling
	Low Load Factor with Cooling
	Export
Market Segmentation: Size	50-500 kW
	500-1,000 kW
	1-5 MW
	5-20 MW
	>20 MW
Market Segmentation: Region	PG&E
	SCE
	SDG&E
	LADWP
	SMUD
	Other North
	Other South
Major Input Assumptions	Technical Market Potential
	Technology Cost and Performance
	Energy Prices
	Application Load Profile
Economic Calculation Engine	CHP Economic Savings by Market and Size
	Payback Comparison
Market Penetration Estimation	Market Acceptance Curve vs. Payback
	Market Penetration of Economic Market
Model Outputs	Cumulative Market penetration in MW
	Electric, thermal and avoided AC Outputs
	Emissions Impacts

Source: ICF International

2.5.1. Market Segmentation and Forecast Horizon

There are five markets defined by application type. Within each application type, there are five size bins and seven utility regions. Each market application and size are defined in terms of the CHP operating load factor and the degree and type of thermal energy utilization.

The CHP Technical Potential described in Section 2.4. by individual market SIC code is grouped into five market sectors as described below:

- High load factor markets are applications that have electric and thermal load around the clock, such as industrial facilities.
- Low load factor markets are applications that have more daily load variation and are generally not considered to be 24-hour facilities like car washes, health clubs, and laundries.

- High load factor heating and cooling markets are 24/7 facilities that require a constant amount of baseload electricity and can utilize available thermal energy in a combination of heating and cooling applications such as nursing homes, colleges, and hospitals.
- Low load factor heating and cooling markets are facilities with shorter operating hours that need to operate a CHP system intermittently using available thermal energy for both heating and cooling. Representative applications in this category include schools, post offices, and office buildings.
- Export markets are high load factor applications that can size CHP to on-site thermal loads and have enough power to cover on-site use with additional power to sell back to the utility. This market consists of process industries that typically have high thermal loads in comparison to their electric loads. The market is considered separately in the model because power sold back to the utility is at a different price than the avoided cost of power used on-site. This market is just the incremental portion of CHP at facilities that contain both on-site and export power.

Within each of these five market segments, CHP economic competition is considered in five size bins as shown in **Table 39**. Each size bin has its own assumptions about load factor and degree of thermal energy used. In addition, each size bin has the CHP technology characterized that is appropriate for that size range.

Table 39: Electric Load, Thermal Utilization, and Technology Assumptions by Size Bin

CHP Market Size	Equivalent Full Load Hours of Use	Thermal Utilization	Competing CHP Technologies
50-500 kW	HiLF = 7,008 LoLF = 4,500	H only Markets 80% H / 0% C H/C Markets 40% H / 40% C	100 kW ICE 65 kW MT 200 kW PAFC
500-1,000 kW	HiLF = 7,008 LoLF = 4,500	H only Markets 80% H / 0% C H/C Markets 40% H / 40% C	800 kW ICE 250 kW MT x 3 300 kW MCFC x 2
1-5 MW	HiLF = 7,008 LoLF = 4,500	H only Markets 80% H / 0% C H/C Markets 40% H / 40% C	3000 kW ICE 3000 kW GT 1500 kW MCFC
5-20 MW	HiLF = 7,446 LoLF = 4,500	H only Markets 90% H / 0% C H/C Markets 45% H / 45% C	5 MW ICE 10 MW GT
>20 MW	HiLF = 8059 LoLF = 4,500	H only Markets 100% H / 0% C H/C Markets 50% H / 50% C	40 MW GT

Abbreviations

Load Factor:	HiLF = High load factor, LoLF = Low load factor
Thermal	H = heating (boiler replacement)
	C = cooling (electric AC replacement)
Technology	ICE = Internal combustion engine
	MT = Microturbine
	PAFC = phosphroic acid fuel cell
	MCFC = molten carbonate fuel cell
	GT = gas turbine

Source: ICF International

The seven utility regions consist of the three major investor owned utilities: SCE, PG&E, and SDG&E. Two large municipal utilities are also represented: LADWP and SMUD. All other utilities are represented in two categories as Other South and Other North. These regions are used to determine the retail electric prices and to define the CHP technical potential. The regions are determined approximately, primarily at the county level with an allocation within Los Angeles County reflecting the SCE, LADWP, and other municipal utilities share of electricity sales. Retail prices are analyzed for the named utilities. The two "Other" categories are assumed to be dominated by smaller municipal utilities. These categories are given the average of the two municipal rates.

The cumulative market penetration is forecast in five year increments. For this analysis, the forecast periods are 2014, 2019, 2024, and 2029.

2.5.2. Market Model Input Assumptions

The major inputs to the ICF CHP Market Model are as follows:

- CHP technical market potential
- CHP technology cost and performance figures
- Energy prices
- Application profiles

Technical Market Potential Inputs

The target market is composed of the facilities that make up the technical market potential as defined previously in *Section 2.4.* This potential is analyzed application by application, but the results are aggregated into the five market sectors and seven utility regions described previously. Facilities of like load factor, size, and thermal characteristics are assumed to offer the same economic opportunity for CHP. A summary of the technical market potential is shown in **Table 40.**

Table 40: Existing Facility and New Technical Market Potential by System Size and Market Segment

Market	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW	Total MW
In Existing Commercial and Industrial Facilities						
High Load Factor	1,152	624	1,522	1,042	245	4,584
Low Load Factor	111	10	5	15	0	141
High Load Factor Cooling	591	269	922	714	563	3,059
Low Load Factor Cooling	2,270	492	746	194	41	3,743
Export	71	110	261	571	3,530	4,544
Total	4,197	1,504	3,456	2,535	4,379	16,071
In New Commercial and Industrial Facilities						
High Load Factor	152	75	172	64	25	488
Low Load Factor	28	2	1	4	0	35
High Load Factor Cooling	164	70	243	151	112	740
Low Load Factor Cooling	458	119	172	30	6	786
Export	22	16	39	45	175	297
Total	**823**	**283**	**628**	**294**	**318**	**2,346**

Source: ICF International

CHP Technology Cost and Performance

The individual technologies that compete for market share within the economic calculation in the model were summarized above in **Table 39** and described in detail in Section 2.2. The CHP costs are adjusted as applicable for the following factors:

- Construction costs in the California regions were adjusted from the national average values shown in Section 2.2 by the capital cost multipliers shown in **Table 41**.
- Early market cost multipliers are included in the early years to reflect additional costs for siting, packaging, and engineering. These factors range from 5-20% and are gradually reduced to zero by the end of the forecast period. These cost multipliers are highest in the small "packaged" CHP sizes and lowest in the large systems that are already well established.
- The federal CHP investment tax credit for CHP is included in the first 10 years of the forecast period.
- The existing SGIP incentive of $2,500/kW is included for fuel cells in the first 10 years of the forecast period. Alternative SGIP scenarios that are considered in the study only include other technologies in the program. The assumed fuel cell incentive is not changed.

Table 41: Capital Cost Multipliers

Utility Region	Cost Multiplier
LADWP	108%
Other North	112%
Other South	108%
PG&E	118%
SCE	108%
SDG&E	106%
SMUD	112%

Source: Means Online Quick Cost Estimator

Energy Prices

The relationship between delivered natural gas and electric prices is at the heart of CHP economic competition. These prices are estimated for each size bin and market load type. These estimates are described in detail at the end of this section.

Application Profiles

As shown previously in **Table 39**, each CHP application is described in terms of its electric load factor and degree and type of thermal utilization. These profiles determine the CHP electric and thermal outputs and the economic savings.

2.5.3. Economic Competitiveness of CHP and Market Acceptance

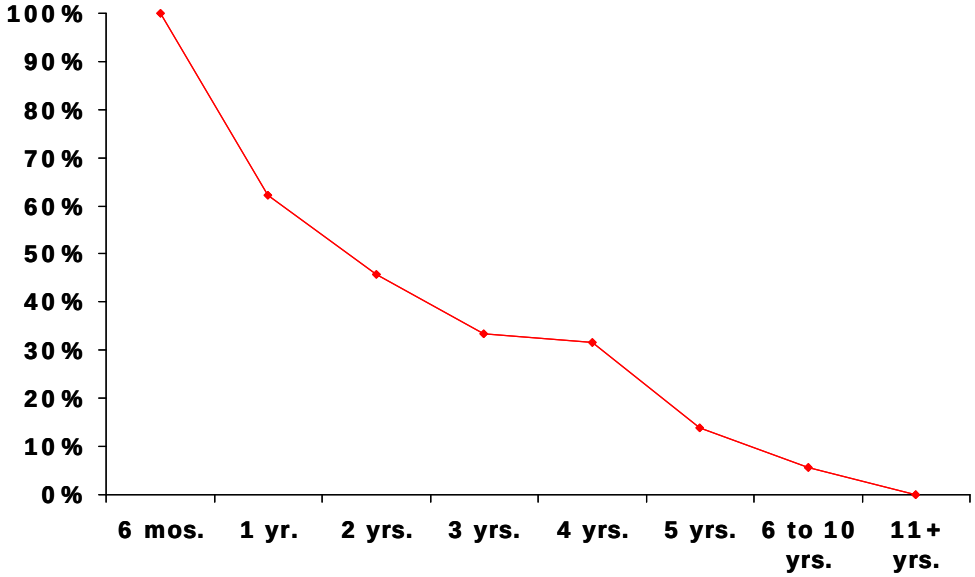
The economic competitiveness calculation within the ICF CHP Market Model is a simple pay-back calculation. The annual cost of operating the CHP system is compared to the avoided thermal and electric energy cost savings, allowing the number of years it would take for this annual savings to repay the initial capital investment to be calculated. Using a simple payback calculation is a very common form of screening to identify potentially economic investments of any type, and it is used by facility operators and CHP developers in the early stages of identifying economic CHP projects.

The annual savings calculation consists of the following components:

- CHP operating cost (on a per kW basis) is a function of the system heat rate, the CHP natural gas rate, and the assumed equivalent full load hours of operation per year.
- Avoided electric cost is a function of the CHP hours of operation and the avoided CHP electric costs.
- Avoided thermal energy is a function of the share of avoided boiler use and avoided air conditioning use. In cooling applications, the share is assumed to be 50/50. In non-cooling applications all thermal energy is assumed to be from avoided boiler fuel.
    - Avoided boiler use depends on the thermal energy per kWh produced by the CHP system, the assumed percentage of thermal energy utilized, the boiler fuel price, and the boiler efficiency.

- Avoided air-conditioning use depends on the CHP thermal energy produced, the assumed efficiency of the absorption chiller, the assumed efficiency of the electric chiller (0.68 kW/ton used) and the avoided air conditioning electric rate.

The payback period is calculated for each competing technology in the size bin. The CHP technology with the lowest payback period is assumed to define the market acceptance rate that is calculated based on a survey of California business facilities that could potentially implement CHP. **Figure 26** shows the percentage of the market that would accept a given payback period and move forward with a CHP investment based on survey results. As can be seen from the figure, more than 30% of customers would reject a project that promised to return their initial investment in just one year. A little more than half would reject a project with a payback of two years. This type of payback translates into a project with a return on investment (ROI) of between 49–100%.



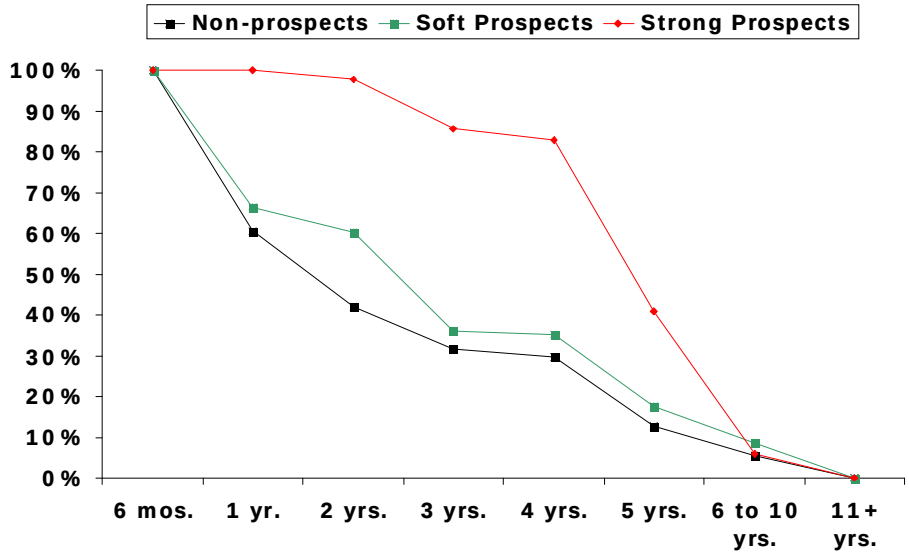
Source: *Primen's 2003 Distributed Energy Market Survey*

Figure 26: Share of the California Customers That Will Accept a Given Payback for a Proposed CHP Project

This acceptance curve is used to determine the share of the technical potential in each utility and size market segment that will go forward with CHP based on the calculated payback for that market segment. As indicated the low acceptance levels for payback periods below four years imply a very high risk perception on the part of potential CHP project implementers.

Potential explanations for rejecting a project with such high returns is that the average customer does not believe that the results are real and is protecting himself from this perceived risk by requiring very high projected returns before a project would be accepted, or that the facility is very capital limited and is rationing its capital raising capability for higher priority projects (market expansion, product improvement, etc.). Arguments can be made that these acceptance rates should be higher. They are used in the model because they reflect actual expected customer behavior in the absence of any change in perceptions regarding the risk of investing in CHP.

Potential large CHP exporters are more sophisticated than the average facility operator and also may be more committed to making economic energy investments. For these customers, a different acceptance curve was used based on the earlier survey work. This curve was for survey respondents characterized as s*trong prospects*. Strong prospects, those that said they were actively evaluating on-site generation options and were more than 50% likely to go forward with a project in the next two years, were willing to accept longer paybacks – up to a point. Almost 90%of strong prospects would consider a payback of four years, but acceptance begins to drop rapidly once paybacks reach five years. **Figure 27** shows the market acceptance curve for strong prospects that was used to define the market acceptance for the large export market.



Source: *Primen's 2003 Distributed Energy Market Survey*

Figure 27: Market Acceptance of Different Payback Periods by Customer Interest in CHP

The allocation of the accepted market share among the competing CHP technologies is based on a *logit* function that defines the market share of the competing CHP systems based on a power function of the economic value of that technology (the payback) divided by the sum of the power functions of all of the competing technologies. To allow this function to work correctly, negative paybacks are converted to a positive (but very unattractive) payback of 100 years.

The rate of market penetration of the economic market potential is based on a Bass diffusion curve with allowance for growth in the maximum market. This function determines cumulative market penetration for each five-year period. Smaller size systems are assumed to take a longer time to reach maximum market penetration than larger systems because there are a larger number of decision-makers requiring an expansion over time of the number of CHP developers. Cumulative market penetration using a Bass diffusion curve takes a typical S-shaped curve. In the generalized form used in this analysis, growth in the number of ultimate adopters is allowed. The curve's shape is determined by an initial market penetration estimate, growth rate of the technical market potential, and two factors described as internal market influence and external market influence. In the out-years the diffusion curve approaches the underlying growth rate of the market being considered. **Figure 28** shows how changing the growth rate of

the technical market potential changes the market penetration curve. If the market has no growth (no new facility technical potential), then the cumulative market penetration will approach 100% of the existing market in year zero. As the growth rate increases, the market will approach the defined annual growth rate. The use of this functional form allows the model to consider the addition of new technical market potential to the existing technical market potential in an orderly fashion.

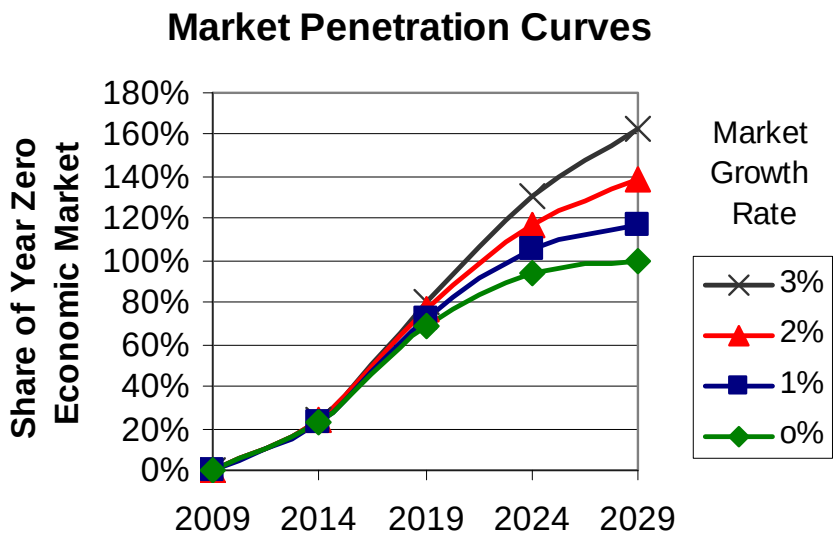


Figure 28: Bass Diffusion Curves for 50-500 kW Market for a Range of Market Growth Rates

Source: ICF International

2.5.4. CHP Output Variables

The basic structure of the ICF CHP Market Model is to determine cumulative growth in CHP market penetration capacity. Based on these capacity results, output variables are calculated based on the input assumptions as follows for each forecast time period:

- Electricity generation
- Avoided AC capacity and avoided AC generation
- CHP fuel consumption and avoided boiler fuel
- Energy savings
- GHG site emissions and overall avoided GHG emissions

The model also has the capability to track criteria pollutant emissions and to define the market shares for competing CHP technologies; however, these two functions were not used for this study.

3.0 Project Results

This section describes the results of the CHP market penetration analysis. The team prepared a Base Case to reflect current market conditions and policies and four alternative cases that contain CHP stimulus measures including restoration of the SGIP, implementation of payments to CHP operators for CO_2 emissions reductions compared to separately purchased fuel and power, addition of an effective economic mechanism for the export power from facilities larger than 20 MW, and an "All-In" case that includes all of these measures combined.

Common assumptions for all scenarios include the estimate of technical market potential, the retail natural gas and electricity prices, the appropriate CHP export prices, and the CHP cost and performance. These assumptions are described in the *Project Approach*.

In addition all scenarios include the 10% federal tax credit for qualifying CHP facilities up to 50 MW in size. Fuel cell systems receive a 30% tax credit. These federal incentives are assumed to be in place for the first 10 years of the forecast time horizon.

3.1. Base Case

The Base Case represents the expected CHP market penetration under the existing regulatory and incentive structure for CHP.

3.1.1. Base Case Input Assumptions

Assumptions specific to the Base Case consist of the following:

- The existing SGIP incentives (limited to fuel cells, wind and associated storage) continue for the next 10 years.
- The AB 1613 export tariff described in the approach is assumed to apply for all export projects up to 20 MW.
- There is no economic contract mechanism in place for export of power from projects larger than 20 MW.

3.1.2. Base Case Results

Figure 29 shows the penetration by utility. In the 20-year forecast period there is 2,731 MW of CHP market penetration. Together, SCE and PG&E will account for 75% of the market in roughly equal shares. **Figure 30** shows the market penetration by CHP system size. In the Base Case the largest share of the market penetration will be in sizes below 5 MW. This distributed generation CHP market makes up 65% of the total market penetration. The 5 to 20 MW size category makes up 25% of the market. Without a mechanism for export of power in the greater than 20 MW size category, these large systems will make up only 10% of the new market penetration expected over the next 20 years.

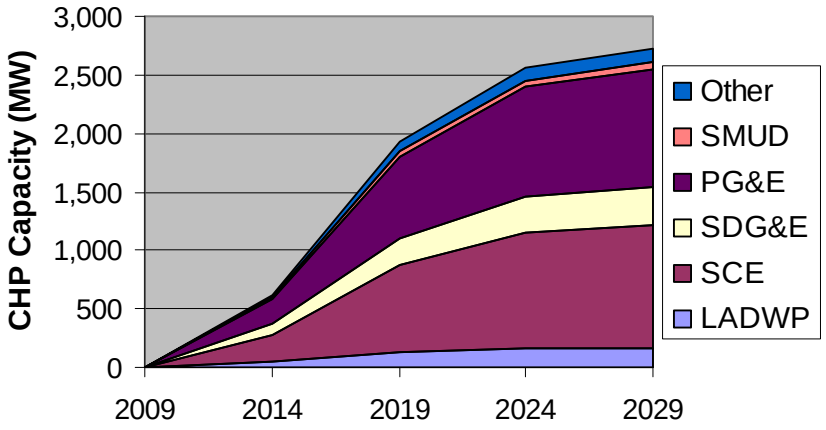


Figure 29: Base Case Cumulative New CHP Market Penetration by Utility

Source: ICF CHP Market Model

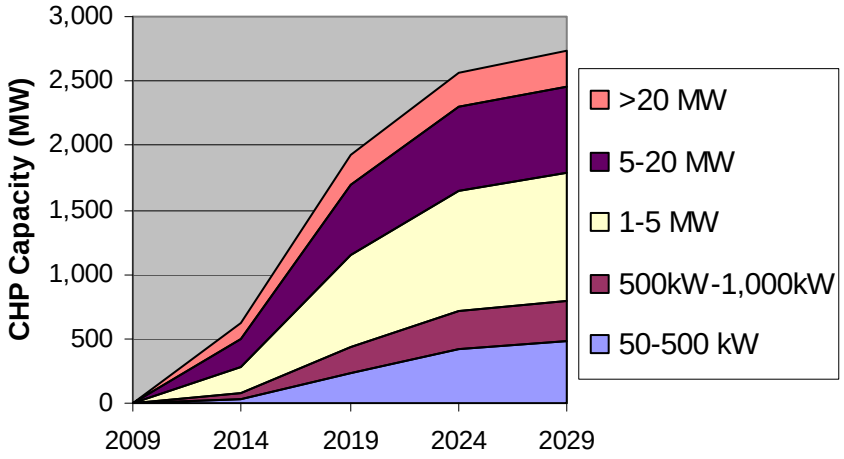


Figure 30: Base Case Cumulative CHP Market Penetration by Size Category

Source: ICF CHP Market Model

Figure 31 shows the market penetration by major market type. The figure shows that the 2,731 MW of cumulative CHP market penetration is mostly for systems that provide power for on-site use. Only 304 MW of market penetration are forecast for export of power under the AB 1613 program. In addition to the total CHP generator capacity, there will be 267 MW of avoided electric capacity that would have otherwise been needed to supply for air conditioning in CHP systems that provide both heating and cooling from their thermal energy output. Therefore, the total capacity impact of the CHP market penetration for the Base Case is equal to nearly 3,000 MW.

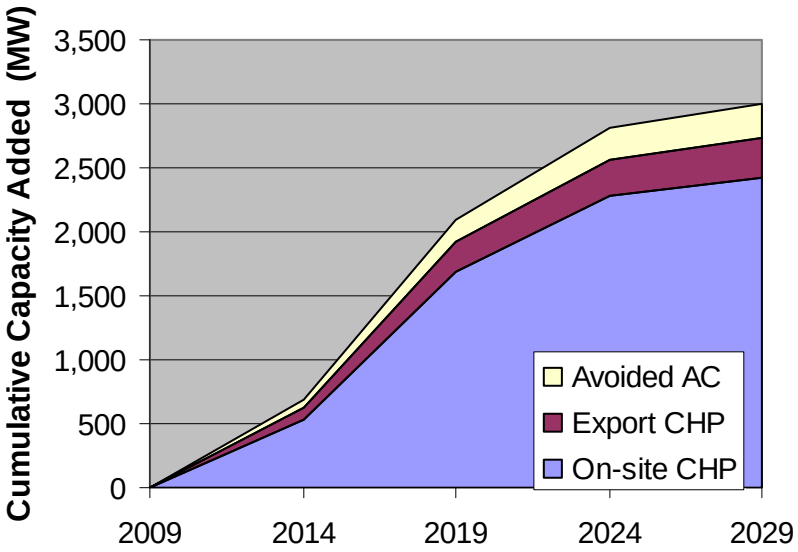


Figure 31: Base Case Cumulative Market Penetration by Market Type

Source: ICF CHP Market Model

The focus of this analysis and of the ICF CHP Market Model is on new CHP market penetration as shown in the previous figures. To put the new CHP market penetration into perspective, **Figure 32** shows the same market penetration as was shown in **Figure 29** but shows this penetration on top of the CHP that is in the California market today. There are roughly 8,800 MW of CHP in the market already; the Base Case forecast shows an additional 3,000 MW being added over the next 20 years. Existing CHP, assuming no retirements, will comprise 75% of CHP capacity in 20 years and new systems that enter the market during this period only 25%.

Figure 33 shows a "what-if" view of the CHP market if the 5,600 MW of existing QF contract capacity is eliminated in the next five years. Although only an illustration, not a forecast or an analytical result of this work, the figure does show that new market penetration would not be able to offset the loss of existing QF capacity and that, if that capacity were eliminated, CHP in the market in 2029 would be lower than today.

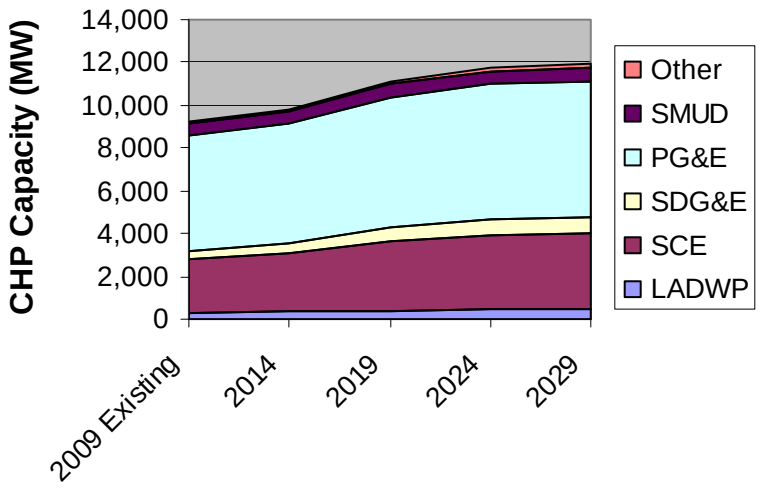


Figure 32: Cumulative Base Case CHP Market Penetration Added to Existing 2009 CHP

Source: ICF CHP Market Model, ICF CHP Installation Database

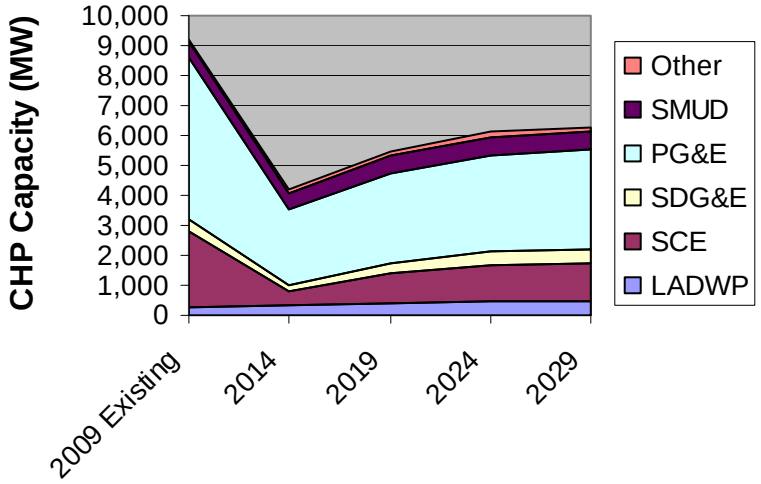


Figure 33: Cumulative Base Case Market Penetration if Existing QF CHP Is Eliminated by 2014.

Source: ICF CHP Market Model, ICF CHP Installation Database

3.2. Incentive Cases

In the incentive cases, three separate CHP incentive measures are evaluated separately to determine their impact on future CHP market penetration. Finally, these incentives are all combined in an "All-In" Case to show the impact of an aggressive set of policy measures to promote CHP in the California market.

3.2.1. Incentive Case Input Assumptions

This section describes the assumptions for the incentive cases analyzed.

CO_2 Payments Case

CHP is a more efficient use of energy than is separately purchasing boiler fuel and electricity. The CHP operator does not gain any special benefit from this fact, only from the reduction in operating costs at the site. Benefits of CHP that contribute to State or federal policy goals such as increased efficiency or CO_2 emissions reduction are external to the decisions to build and operate CHP. Providing CHP operators with a payment for reducing overall CO_2 emissions would internalize this benefit into the CHP deployment decision and stimulate the CHP market based on the social value of emissions reduction that is provided.

In the calculation of the Market Price Referent[30] (MPR) for the renewable feed-in tariff, there is a component to add in the cost to utilities of emitting GHGs from their fossil generation. These costs begin in 2015 at $23/ton of CO_2 and grow to $88/ton by 2029. Unlike renewable power sources, CHP does not eliminate 100% of the GHG emissions associated with the power generation provided, but CHP systems do provide savings compared to central station power generation, as will be shown in **Section 3.3.2**. The benefit for CHP provided GHG emissions reductions should be included in the economic decision to own and operate CHP in the form of annual payments for GHG reductions according to the value of these emissions reductions—$23/ton in 2015 increasing to $88/ton by 2029.

Due to limitations of the model, an annually changing price track for CO_2 reductions could not be modeled. Instead, an average value of $50/ton of CO_2 emissions reduction is provided for all CHP electric output and for avoided electricity generation due to CHP supplied air conditioning.

CO_2 payments are not applied to AB 1613 eligible export power because the price track used for this power is the MPR value that already includes the GHG adders.

When all incentive measures are considered together (in the "All-In" Case), the CO_2 payment is provided for large export projects (greater than 20 MW) using the estimated contract prices shown in the approach, because these contract price tracks do not include any CO_2 adjustment.

Restore SGIP Case

Restoration of the SGIP is included in Senate Bill 412 (Kehoe, Chapter 182, Statutes of 2009), passed by the California Legislature and signed into law by the Governor on October 11, 2009. Under this bill, the CPUC is required to re-implement SGIP using their discretion about

30 2008 MPR Model E4214 Final Publci.xls, E3, CPUC, 2008.

program details. For this analysis we assumed that all SGIP payments would be restored as they existed before they were suspended in 2007 and that the current phased expansion of benefits for projects up to 5 MW would be included as well.

The SGIP payments are made as an upfront incentive to offset some of the capital costs of the CHP system. The payments vary by fuel use and technology. For fossil-fueled systems, representing the focus of this analysis, the payments are $600/kW for reciprocating engines, $800/kW for microturbines, and $2,500/kW for fuel cells. The full SGIP incentive payment is applied to the first MW for qualifying systems under 5 MW of capacity. A partial payment of 50% is applied to the second MW of capacity and 25% incentive for the third MW of capacity for systems with a total size of 5 MW or less.

The analysis is based on the assumption that the SGIP will be in place for the first 10 years of the forecast time horizon.

Basic Large Export Case

The AB 1613 CHP feed-in tariffs, apply only to systems 20 MW or less. In the Base Case, no mechanism for exporting power from larger facilities (greater than 20 MW) is assumed. In this first of two expanded export scenarios, export of power from large facilities is assumed to be at a contract price reflecting the cost of power generation from a combined cycle power plant using the plant cost and performance characteristics given in an Energy Commission staff report.[31]

Facilities in the large export market were assumed to be strong prospects, meaning their acceptance curve for project paybacks is much stronger than the average market acceptance curve used for the other markets.

The contract pricing assumptions for this case were shown previously in **Figure 22** (marginal electric generation cost) and **Figure 24** (large contract price). The special market acceptance curve used for these large projects is shown in **Figure 27** (strong prospects).

"All In" Incentives Case

The "All-In" Case represents a combination of all the previous incentive cases (including restoration of SGIP, addition of CO_2 emissions reduction payments of $50/ton, and expanding export contracting to facilities larger than 20 MW) and an additional inclusion of an aggressive contract pricing mechanism and accompanying CO_2 payments. This more aggressive contract price track for large export CHP projects is evaluated as shown in **Figure 24** (aggressive contract price) and described in the accompanying text as a modification of the existing MPR calculation methodology. As previously described, it is appropriate to use this price with an accompanying CO_2 emissions reduction payment. Therefore, this price track is used in the "All-In" Case in place of the basic large export case assumptions just described.

31 *Comparative Costs of Central Station Electricity Generation*, Draft Staff Report, CEC-200-2009-017-SD, August 2009.

3.2.2. Incentive Case Results

Figure 34 and **Table 42** show the cumulative CHP market penetration for the incentive cases. The figures include both CHP generation and avoided air conditioning. The range of market penetration from the Base Case to the "All-In" Case is from 3,000 to 6,500 MW. The case results can be summarized as follows:

- CO_2 payments increase market penetration by 244 MW.
- The restoration of SGIP for the next ten years increases market penetration by 497 MW.
- Expanding export contracting to facilities larger than 20 MW with a basic contracting mechanism increases market penetration by 1,441 MW. All of this increase in export market penetration is for facilities larger than 20 MW.
- In the "All-In" Case, which includes all incentive measures plus a more aggressive large export contract price, the market increases by 3,521 MW – 79% of this increase is in the export market.

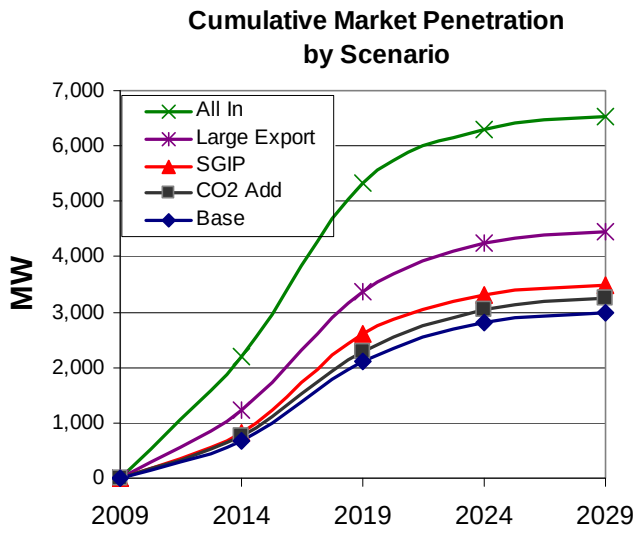


Figure 34: Cumulative Market Penetration Forecasts for All Scenarios

Source: ICF CHP Market Model

Table 42: 2029 Cumulative Market Penetration by Market Type

	CHP 2029 Capacity, MW				
Market Type	**Base**	**CO_2 Payment**	**Restore SGIP**	**Expanded Export**	**"All In"**
On-Site	2,427	2,658	2,866	2,427	3,095
Export	304	304	316	1,745	3,100
Air Conditioning	267	281	314	267	325
Total	**2,998**	**3,242**	**3,496**	**4,439**	**6,519**

Source: ICF CHP Market Model

Export Market Issues

The Large Export Market for CHP systems larger than 20 MW, is assumed to be completely shut out of the Base Case market. With an aggressive, yet economically justifiable contract price coupled with payments for CO_2 emissions reduction, this sector contributes 2,714 MW to the "All-In" Case. The contribution from this sector shown at the July 23, 2009, workshop, based on preliminary results, was much smaller—only 671 MW. Public comment on these preliminary results challenged two areas of the preliminary assumptions:

- The assumed contract price
- The degree to which large customers would accept favorable economic signals (attractive project paybacks)

Figure 35 shows the changes that were made to the input assumptions that contributed to this large change in the outlook for market penetration from large CHP systems. The preliminary results of 671 MW were based on the assumption that the large customers would behave like average customers and that 25% would accept the roughly 5-year payback offered by a basic contracting mechanism. Changing this assumption to the strong prospects acceptance curve (Step 1) increases the acceptance rate for a 5-year payback to about 50% with a resulting market penetration of roughly 1,400 MW. Adding a more aggressive contract pricing mechanism with CO_2 payments brings the payback period down to about 3 years or less. With this economic incentive, the large customers (strong prospects) have about a 90% acceptance or about 2,700 MW.

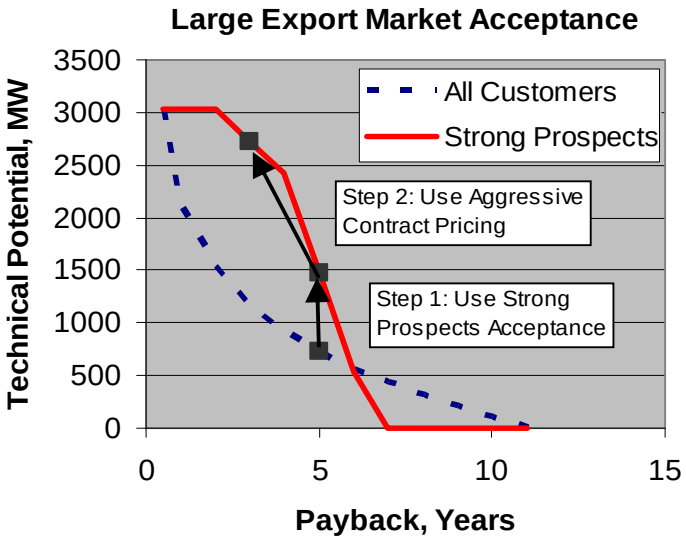


Figure 35: Impact of Assumptions on Large Export Market Penetration

Source: ICF Adaptation of Primen Survey Results in the 2005 CHP Market Assessment

3.3. Energy and Environmental Impacts

The energy and environmental value to customers and to the state is in the power that the CHP capacity produces and the efficiency improvements and GHG emissions reductions that can be achieved. This section describes the energy and environmental impacts of CHP market penetration by scenario.

3.3.1. Energy Impacts

Table 43 shows the energy output characteristics of the cumulative CHP market penetration by scenario.

- Total CHP capacity by 2029, including avoided electric air conditioning capacity, ranges from 2,988 MW in the Base Case to 6,515 MW in the "All-In" Case.
- This cumulative capacity will produce 18,991 to 45,779 million kWh per year by 2029.
- Natural gas for CHP generation will require 188 trillion to 400 trillion Btu per year but will reduce boiler fuel consumption by 50 trillion to 143 trillion Btu per year.
- Average CHP load factors range from 75.6 to 82.6%, and effective CHP efficiencies range from 62 to 68%. The variation is due to the change in market shares for different types of CHP by scenario.
- Energy savings will range from 39 trillion to 102 trillion Btu per year by the end of the forecast period.

Table 43: Scenario Comparison of Capacity, Outputs, Efficiency, and Load Factor for 2029

Scenario Characteristic	Base Case	CO_2 Payment	Restore SGIP	Expanded Export	"All-in"
Market Penetration (MW)	2,731	2,965	3,182	4,172	6,195
Avoided Electricity for cooling (MW)	267	281	314	267	325
Total Capacity (MW)	2,998	3,246	3,496	4,439	6,519
Fuel Consumption (billion Btu/yr)	168,295	180,976	195,193	268,094	399,788
Avoided boiler fuel (billion Btu/yr)	50,343	54,532	58,514	92,311	143,346
Electricity Generated (million kWh/yr)	18,293	19,807	21,086	29,892	44,955
Avoided Electricity for cooling (million kWh/yr)	698	726	800	698	824
Total Electricity (million kWh/yr)	18,991	20,533	21,887	30,590	45,779
Energy Savings (billion Btu/yr)	36,722	40,911	42,093	65,418	101,675
Average CHP Load Factor (%)	76.5	76.2	75.6	81.8	82.8
Average Avoided AC Load Factor (%)	29.8	29.5	29.1	29.8	29.0
Average Heat Rate (Btu/kWh)	9,200	9,137	9,257	8,969	8,893
Effective CHP Efficiency (%)	62.4	62.8	62.3	66.5	67.8

Source: ICF CHP Market Model

Table 44 shows the output characteristics for the five submarkets that comprise the "All-In" Case. The differences by market segment are as follows:

- The largest contribution to market penetration in this scenario is the export market.

- CHP in high load factor on-site markets operates at an average 82-84% load factor. Low load factor markets all operate 4500 hours per year or 51.4% load factor.
- CHP markets with cooling have the lowest effective CHP efficiency, operating between 54-56% efficiency.[32] On-site markets without cooling operate at an average 68% CHP efficiency. The use of thermal energy from CHP to offset electric air conditioning requires 10,500 to 17,000 Btu/ton of cooling. A ton of cooling from a typical electric chiller requires about 0.65 kW/ton. Therefore, the addition of cooling is the equivalent of adding "generation" at a heat rate of between 16,000 and 26,000 Btu/kWh.
- In the export market, dominated by large systems in the "All-In" Case, the systems operate at an average 91% load factor and a 73% CHP efficiency, making this market the highest contributor to energy output and energy savings.

Table 44: All-In Case Output Summary by Submarket Type for 2029

Scenario Characteristic	High Load Factor	Low Load Factor	High Load Factor Cooling	Low Load Factor Cooling	Export	All-in Case Total Market
Market Penetration (MW)	1,412	37	916	730	3,100	6,195
Avoided Electricity for cooling (MW)	0	0	188	136	0	325
Total Capacity (MW)	1,412	37	1,104	867	3,100	6,519
Fuel Consumption (billion Btu/yr)	92,218	1,706	61,472	31,572	212,820	399,788
Avoided boiler fuel (billion Btu/yr)	35,872	730	11,929	6,270	88,546	143,346
Electricity Generated (million kWh/yr)	10,103	167	6,722	3,287	24,676	44,955
Avoided Electricity for cooling (million kWh/yr)	0	0	576	248	0	824
Total Electricity (million kWh/yr)	10,103	167	7,298	3,535	24,676	45,779
Energy Savings (billion Btu/yr)	22,789	595	9,936	8,546	59,809	101,675
Average CHP Load Factor (%)	81.7	51.4	83.8	51.4	90.9	82.8
Average Avoided AC Load Factor (%)	n.a.	n.a.	34.9	20.8	n.a.	29.0
Average Heat Rate (Btu/kWh)	9,128	10,212	9,145	9,606	8,625	8,893
Effective CHP Efficiency (%)	68.5	67.6	56.0	54.1	72.9	67.8

Source: ICF CHP Market Model

3.3.2. GHG Emissions Impacts

The GHG emissions reduction that will be achieved by additional CHP market penetration is a critical part of the policy debate on the regulatory treatment of CHP and proposed incentives. CHP systems operating on natural gas are themselves emitters of GHGs. Therefore, the GHG emissions benefits for CHP depends on the degree to which these emissions are lower than the emissions that will be avoided from central station power generation and the use of fossil fuel in boilers or other on-site processes.

32 *Effective CHP efficiency* is defined as the sum of the useful energy provided divided by the generator energy input. The useful energy, as defined here, consists of electricity generated, electric air conditioning avoided, and useful thermal energy provided to boilers or other non-cooling processes. This definition treats the thermally activated air conditioning as a separate electric "generation" process.

Avoided Central Station GHG Emissions Assumptions

The ARB estimated the avoided central power station emissions for its development of targets for CHP penetration in the *Climate Change Scoping Plan*. [33] The central station emissions factor assumed in the ARB study is 0.437 MT CO_2/MWh or 963.4 lb/MWh. This estimate corresponds to a gas-fired generator with an 8,231 Btu/kWh heat rate. In addition ARB assumed line losses of approximately 8.5% raising the avoided emissions on a delivered basis to 1045 lb CO_2/MWh. These same assumptions were used in this study to calculate the GHG savings from avoided central station generation.

GHG Emissions Savings Results

The GHG emissions reductions by scenario are shown in **Figure 36**. Annual GHG savings by the end of the forecast time horizon (2029) range from 2.7 million MT CO_2e to 7.0 million MT in the "All-In" Case. The ARB target for CHP of 6.7 million MT CO_2e reduction by 2020 is also shown on the graph.

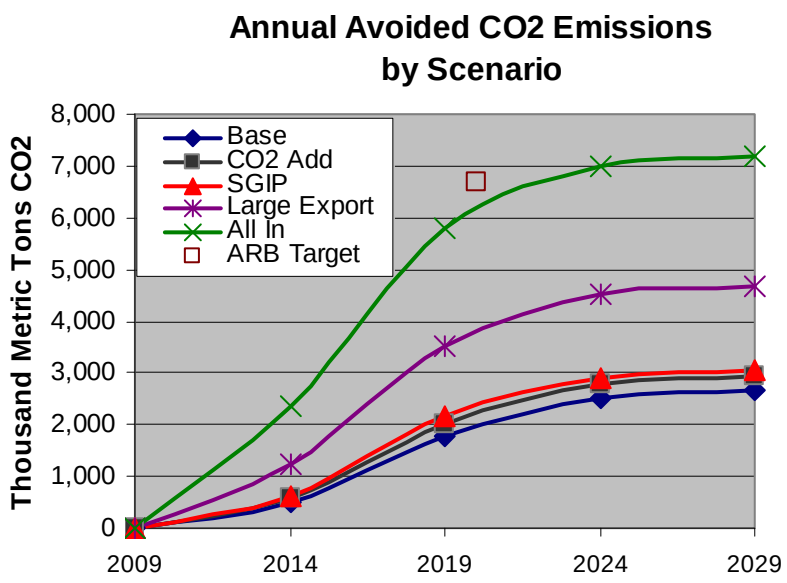


Figure 36: GHG Emissions Savings by Scenario Using ARB Avoided Central Station Emissions Estimate

Source: ICF CHP Market Model

Table 45 compares the study results with the ARB target estimate of GHG emissions savings from CHP by 2020. The ARB estimate was based on export access for all sizes of CHP and restoration of SGIP. These assumptions are similar to the "All In" Case defined for this study. In the Base Case, market penetration by CHP is projected to be only 56% of the ARB target for additional CHP capacity market penetration, and actual power generation and avoided air

33 *Climate Change Scoping Plan Appendices: Volume II: Analysis and Documentation,* California Air Resources Board, December 2008.

conditioning from CHP is less than half of the ARB target. Finally, the emissions saving estimate is only 30% of the ARB estimate. In the "All-In" Case, 2020 market penetration and generation both exceed the ARB estimate, but the expected GHG savings are only 90% of the target 2020 GHG emissions reduction.

Since both the ARB targets and this study are based on the ARB assumption for avoided GHG emissions, the differences to the unit emissions savings shown in the table—492 lb/MWh for ARB and 294-347 lb/MWh for this study—are primarily due to variations in the operating profile and performance of CHP. The differences between this analysis' GHG estimates and ARB's targets are as follows:

- ARB assumes an 85% load factor for CHP. The calculated value for the "All-In" Case is 80.2%.
- ARB assumes an overall CHP efficiency of 77%. The calculated value for the "All-In" Case is 67.8%.

Table 45: Comparison of Study Results GHG Savings to ARB Target Goal

Scenario	Capacity MW	Output GWh/year	Average Load Factor	Avoided CO_2 MMT/year	CO_2 Savings Rate lb/MWh
ARB 2020 Goal	4,000	30,000	85.6%	6.70	492
Base Case 2020	2,240	14,486	73.8%	1.93	294
Base Case 2029	2,998	18,293	69.6%	2.67	322
"All In" Case 2020	5,532	39,545	81.6%	6.05	337
"All In" Case 2029	6,519	45,779	80.2%	7.20	347

Source: ARB and ICF International

The ARB target for CHP was based on the assumption that the market would be stimulated by a combination of incentive and regulatory measures. This analysis indicates the combination of incentives contained in the "All-in" Case – SGIP, CO_2 payments, AB 1613, and large export contracting – can bring California to 90% of the 6.7 million metric ton/year CO_2 reduction target. Additional measures not analyzed in this study, such as capacity payments, production tax credits, and CHP procurement standards, could increase CHP market penetration to higher levels that could meet or exceed the ARB GHG reduction target.

Detailed tables of the model results showing projected market penetration by size, utility, and year are provided in **Appendix C**. A comparison of the 2005 CHP market study assumptions and results to the current study is presented in **Appendix D.**

4.0 Conclusions and Recommendations

Without further changes in CHP regulation or policy (Base Case), about 3,000 MW of CHP capacity (both generation and avoided air conditioning) will penetrate the market over the next 20 years. This forecast is considerably below the ARB AB 32 Scoping Plan target of 4,000 MW over the next 11 years.

An aggressive set of policy measures to stimulate CHP can more than double this market penetration to over 6,500 MW in the next 20 years ("All-In" Case). The policy measures assumed to be implemented to achieve these market results are the restoration of the SGIP program, the addition of payments to CO_2 operators of $50/ton for their effective reductions in CO_2 emissions compared to the separate purchase of grid power and fuel for boiler use, and the creation of an export market for large facilities, not currently covered by AB 1613.

The estimated GHG emissions reductions that will be achieved in each of these alternative futures range from 2.9 million to 7.2 million MT of CO_2 by 2029–1.9 million to 6.0 million MT of CO_2 by 2020.

While the analysis in this study focused on new CHP market penetration, close to 8,800 MW of existing CHP was identified. A large percentage of this CHP, about 5600 MW, is providing power to utilities under existing QF contracts. Existing CHP is larger than the expected growth of new CHP under any scenario in the next 20 years. Therefore, it is important to define regulatory policies that contribute to the preservation of the existing CHP capacity.

During the analysis of existing CHP and the development of estimates for technical potential and market penetration for new CHP, it became clear that there are essentially two types of CHP – projects larger than 20 MW and projects smaller than 20 MW. These two types of projects have differing characteristics and require different measures to stimulate additional market penetration. **Table 46** shows the comparison between large CHP and small CHP. Large CHP has 87% of the existing market penetration. In the Base Case, only a very small amount of large CHP penetrates the market, about 10% of the total penetration for the Base Case. In the "All-In" Case, there is a roughly even split in the market penetration for large and small CHP.

Table 46: Large vs. Small CHP Existing Market and Market Outlook (Generation Only, Avoided AC Not Included)

CHP Markets and Measures	Large CHP (>20 MW), MW	Small CHP (< 20 MW), MW
Existing QF Contracts	6,000	
Other Existing CHP	1,700	1,200
Total Existing	7,700	1,200
New Market Penetration, Base Case	278	2,453
Additional Market Penetration, "All-In" Incentives	2,737	727
Total New "All-In"	3,015	3,180

Source: ICF International

Large and small CHP face different market issues and react to different market stimuli. Small CHP will respond to the restoration of SGIP, the addition of CO_2 payments, and the AB 1613 feed-in tariff. In addition small CHP can profit from programs that reduce the cost of these systems and programs that increase awareness within the target markets of the cost and efficiency advantages of CHP. In the large markets, preservation of existing contracts will be most important followed by the development of an economically attractive mechanism for contracting for new projects. The analysis of technical potential showed that CHP systems sized to the on-site thermal loads within large process industries will produce far more power than can be utilized on site. Therefore, for these projects to move forward, the power must be exported to the grid at an attractive price.

Small CHP has additional benefits for California that were not modeled as part of this study. There will be a reduction in the need for technology and development (T&D) investments if more power is produced on-site by end-use facilities. Small CHP will provide increased system and customer reliability by providing multiple sources of supply and the ability to meet on-site needs during grid outages.

The expansion of CHP, both large and small, will also support technical innovation and support the competitiveness of California business.

There are a number of measures that could help to remove barriers to CHP market penetration:

- Education and training programs to address the lack of information or awareness and to reduce the perceptions of CHP project risk.
- Demonstration of innovative technologies and applications to both reduce the cost of CHP systems and to further increase awareness of CHP capabilities in the target markets.
- CHP project risk, both real and perceived, needs to be addressed through the establishment of long-term contracts, gas contracting mechanisms that reduce the

negative effects of gas price volatility, and improvement of CHP technology cost and performance.

- Reduction in the degree of non-bypassable charges that CHP must pay and encouraging economic treatment for CHP.
- Provision of incentives to internalize the social benefits of CHP energy efficiency, GHG emissions reductions, T&D support, peak capacity, and system reliability.

The quantification of the GHG emissions reduction benefits due to CHP deployment and use depends on the emissions of the central power being displaced. Further work should be done to determine what the marginal source of power will be over the next 20 years and what are the appropriate values to use when comparing to baseload CHP, low load factor CHP, and for avoided electric air conditioning. In addition to defining the marginal sources of power during different time periods, it is also important to evaluate the expected line losses appropriate for different types and sizes of CHP at different times of the year.

Improved methods for measuring and accounting for the thermal energy utilization need to be developed and deployed because the utilization of thermal energy provides the added benefits for CHP compared to the separate purchase of fuel and power. High thermal utilization needs to be specifically encouraged. In this regard, higher efficiency absorption chillers or other thermally activated cooling technologies need to be developed and demonstrated to improve the GHG emissions performance of CHP in applications with cooling.

Glossary

AB 1613	Waste Heat and Carbon Emissions Reduction Act
AB 1969	Renewable electric generation facilities: feed-in tariffs (actually AB-1807)
AB 32	California Global Warming Solutions Act 2006
AC	Air conditioning
AEO	Annual Energy Outlook, long-range forecast publication of EIA
ARB	California Air Resources Board
AT	after-treatment control
CBECS	Commercial Buildings Energy Consumption Survey, publication of EIA
CEPD	Commercial Energy Profile Database
CEUS	Commercial End-Use Survey
CCHP	Combined cooling, heating, and power
CHP	Combined heat and power
CO_2	Carbon dioxide
CPUC	California Public Utilities Commission
D&B	Dun & Bradstreet
DER	Distributed energy resources
DLE	Dry low emission
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
ECDMS	Energy Consumption Data Management System
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPG	Electric power generation
FIT	Feed-in tariff
GDP	Gross domestic product
GHG	Greenhouse gas: There are a number of gases classified as "greenhouse gases" including CO_2, methane and N_2O. This analysis considers only the impact on CO_2 emissions, the principal greenhouse gas reduced from the deployment of CHP.
GT	Gas turbine
GT-CC	Gas turbine combined-cycle
GTI	Gas Technology Institute
HHV	Higher heating value
HVAC	Heating, ventilation, and air conditioning
IEPR	*Integrated Energy Policy Report*
IOU	Investor-owned utility
LADWP	Los Angeles Division of Water and Power
LBNL	Lawrence Berkeley National Laboratory
LHV	Lower heating value
MCFC	Molten carbonate fuel cell
MECS	Manufacturing Energy Consumption Survey, publication of EIA

MIPD	Major Industrial Plant Database
MPR	Market price referent
MT	Metric ton, equal to 2,205 pounds
NAICS	North American Industry Classification System
NO_x	Nitrogen oxides
NREL	National Renewable Energy Laboratory
NYSERDA	New York State Energy Research and Development Agency
ORNL	Oak Ridge National Laboratory, U.S. Department of Energy
PAFC	Phosphoric acid fuel cell
PEM	Proton exchange membrane
P/H	Power-to-heat ratio
PG&E	Pacific Gas and Electric Company
PURPA	Public Utility Regulatory Policies Act of 1978
QF	Qualifying facility, legal designation of CHP under PURPA
SB 412	Requires CPUC to continue SGIP
SCE	Southern California Edison Company
SCR	Selective catalytic reduction
SDG&E	San Diego Gas & Electric Company
SGIP	Self-Generation Incentive Program
SI	Spark ignition
SIC	Standard Industrial Classification
SMUD	Sacramento Municipal Utility District
SOFC	Solid oxide fuel cell
T&D	Transmission and distribution
WECC	Western Electric Coordinating Council

APPENDIX A: Existing CHP Detailed Tables

Table A-1: Existing CHP Operating in 2008 by Application and Fuel Type

		Biomass		Coal		Natural Gas		Oil		Waste		Wood		Other		Total	
	Application	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
Industrial	SIC 20: Food	1	20.5	2	57.5	55	1,368.0							2	3.0	60	1,449.0
	SIC 22: Textile Products					3	1.8									3	1.8
	SIC 24: Wood Products			1	44.0	2	51.0					13	185.8			16	280.8
	SIC 26: Paper					9	339.8			1	20.0	1	13.5			11	373.3
	SIC 27: Publishing					3	10.7							1	0.1	4	10.8
	SIC 28: Chemicals			1	108.0	13	160.1	1	1.9	2	81.8			5	12.2	22	364.0
	SIC 29: Petroleum Refining					11	839.5			5	311.0			1	51.0	17	1,201.5
	SIC 30: Rubber					1	0.5			1	27.0					2	27.5
	SIC 32: Stone, Clay, Glass					6	51.9							1	24.0	7	75.9
	SIC 33: Primary Metals					8	514.2									8	514.2
	SIC 34: Fabricated Metals					13	2.2									13	2.2
	SIC 35: Machinery					2	1.1									2	1.1
	SIC 36: Electrical Equipment					3	4.3	1	0.9							4	5.2
	SIC 37: Transportation Equip					3	13.1									3	13.1
	SIC 39: Misc Manufacturing					11	19.8							1	7.2	12	27.0
	Total Industrial	1	20.5	4	209.5	143	3,378.0	2	2.8	9.0	439.8	14.0	199.3	11.0	97.5	184	4,347.4
Other	SIC 9900: Unknown	28	13.2			211	106.6							1	0.1	240	119.9
	SIC 01: Agriculture	1	25.0			11	22.0									12	47.0
	SIC 02: Livestock	2	0.9			1	2.5									3	3.4
	SIC 13: Crude Oil			3	124.7	70	2,379.1	3	8.9	2	0.4			2	35.5	80	2,548.5
	SIC 14: Quarrying			1	62.5	3	101.0									4	163.5
	Total Other	31	39.1	4	187.2	296	2,611.2	3	8.9	2	0.4	0	0.0	3	35.6	339	2,882.4
Commercial	SIC 4200: Warehousing/ Cold Storage					7	130.7									7	130.7
	SIC 4500: Air Transportation					3	45.0							1	0.5	4	45.5
	SIC 4800: Communications					6	27.6									6	27.6
	SIC 4939: Utilities	1	4.6			6	176.7			1	17.0			2	0.1	10	198.4
	SIC 4952: Wastewater Treatment	29	84.4			10	86.6							1	0.5	40	171.5
	SIC 4953: Solid Waste Facilites	7	18.8							1	35.6					8	54.4
	SIC 4961: District Energy	1	1.3			2	9.1									3	10.4
	SIC 5000: Wholesale/Retail					2	0.8									2	0.8
	SIC 5411: Food Stores					4	0.8									4	0.8
	SIC 5812: Restaurants					6	0.1							1	0.1	7	0.1
	SIC 6512: Comm. Building					45	32.6									45	32.6
	SIC 6513: Apartments					22	1.5							1	0.1	23	1.6
	SIC 7011: Hotels					65	33.6							3	0.6	68	34.2
	SIC 7200: Laundries					66	2.7							2	0.0	68	2.8
	SIC 7542: Carwashs					1	0.0									1	0.0
	SIC 7990: Amusement/ Rec.					50	59.7							4	0.7	54	60.4
	SIC 8051: Nursing Homes					19	2.9							2	0.1	21	3.0
	SIC 8060: Hospital/Healthcare	1	1.0			45	192.3									46	193.3
	SIC 8211: Schools					110	9.7							6	0.4	116	10.2
	SIC 8220: Colleges/Univ.	1	0.4			44	305.4							2	1.6	47	307.4
	SIC 8400: Zoos/Museums					1	1.4									1	1.4
	SIC 8900: Services NEC					31	9.0							1	0.0	32	9.0
	SIC 9100: Government Fac.					20	41.3							1	0.1	21	41.3
	SIC 9200: Courts/Prisons	1	37.0			14	71.8									15	108.8
	SIC 9700: Military					11	153.2									11	153.2
	Total Commercial	41	147.4	0	0.0	590	1,394.4	0	0.0	2	52.6	0	0.0	27	4.8	660	1,599.2
	Grand Total	**73**	**207.0**	**8**	**396.7**	**1029**	**7,383.6**	**5**	**11.7**	**13**	**492.8**	**14**	**199.3**	**41**	**137.8**	**1,183**	**8,828.9**

Table A-2: Existing CHP Operating in 2008 by Application and Prime Mover

		Boiler/ Steam Turbine		Combined Cycle		Combustion Turbine		Reciprocating Engine		Fuel Cell		Microturbine		Other		Total	
	Application	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
Industrial	SIC 20: Food	5	84.3	9	885.0	13	434.7	26	43.1	2	1.20	5	0.73			60	1,449.0
	SIC 22:Textile Products							3	1.8							3	1.8
	SIC 24:Wood Products	14	229.8	1	49.5			1	1.5							16	280.8
	SIC 26: Paper	2	33.5	2	72.0	7	267.8									11	373.3
	SIC 27: Publishing					2	8.1	2	2.7							4	10.8
	SIC 28: Chemicals	6	203.3	1	28.0	5	124.5	7	7.4			2	0.30	1	0.5	22	364.0
	SIC 29: Petroleum Refining	2	117.0	5	782.0	8	302.3					2	0.22			17	1,201.5
	SIC 30: Rubber	1	27.0					1	0.5							2	27.5
	SIC 32: Stone, Clay, Glass	1	24.0			1	48.4	4	3.3			1	0.24			7	75.9
	SIC 33: Primary Metals			1	512.0			6	1.5	1	0.62					8	514.2
	SIC 34: Fabricated Metals							11	1.8			2	0.36			13	2.2
	SIC 35: Machinery							2	1.1							2	1.1
	SIC 36: Electrical Equipment							3	5.1			1	0.08			4	5.2
	SIC 37: Transportation Equip					2	11.9	1	1.3							3	13.1
	SIC 39: Misc Manufacturing					2	13.9	6	5.5			3	0.39	1	7.2	12	27.0
	Total Industrial	31	718.9	19	2,328.5	40	1,211.7	73	76.5	3	1.8	16	2.3	2	7.7	184	4,347.4
Other	SIC 9900: Unknown					2	2.4	163	102.3	6	3.50	69	11.74			240	119.9
	SIC 01: Agriculture	2	27.7	1	6.5	1	5.5	6	7.0			2	0.21			12	47.0
	SIC 02: Livestock							3	3.4							3	3.4
	SIC 13: Crude Oil	6	188.6	4	223.9	60	2,126.0	9	9.9			1	0.07			80	2,548.5
	SIC 14: Quarrying	1	62.5	1	55.4	1	45.0							1	0.6	4	163.5
	Total Other	9	278.8	6	285.8	64	2,179.0	181	122.7	6	3.5	72	12.0	1	0.6	339	2,882.4
Commercial	Warehousing/ Cold Storage					3	127.5	3	3.0	1	0.25					7	130.7
	SIC 4500: Air Transportation			1	30.0	1	8.0	2	7.5							4	45.5
	SIC 4800: Communications					2	25.5	1	1.4			3	0.72			6	27.6
	SIC 4939: Utilities	1	17.0			4	176.0	4	5.3			1	0.12			10	198.4
	Wastewater Treatment			1	28.0	3	74.7	17	63.6	5	2.95	14	2.21			40	171.5
	SIC 4953: Solid Waste Facilites	1	35.6					6	17.5			1	1.30			8	54.4
	SIC 4961: District Energy							3	10.4							3	10.4
	SIC 5000: Wholesale/Retail							2	0.8							2	0.8
	SIC 5411: Food Stores							4	0.8							4	0.8
	SIC 5812: Restaurants							7	0.1							7	0.1
	SIC 6512: Comm. Building					2	9.5	32	19.6	4	1.80	7	1.68			45	32.6
	SIC 6513: Apartments							21	1.3			2	0.24			23	1.6
	SIC 7011: Hotels					2	5.6	52	25.7	3	1.70	11	1.19			68	34.2
	SIC 7200: Laundries							66	2.4	2	0.40					68	2.8
	SIC 7542: Carwashs											1	0.03			1	0.0
	SIC 7990: Amusement/ Rec.			1	49.8	1	0.1	48	9.3			4	1.20			54	60.4
	SIC 8051: Nursing Homes							20	2.8			1	0.24			21	3.0
	SIC 8060: Hospital/Healthcare	1	32.9	5	106.8	10	29.8	27	23.1	2	0.60	1	0.12			46	193.3
	SIC 8211: Schools							90	8.1			26	2.05			116	10.2
	SIC 8220: Colleges/Univ.			7	188.8	6	91.5	25	24.1	2	1.36	7	1.62			47	307.4
	SIC 8400: Zoos/Museums							1	1.4							1	1.4
	SIC 8900: Services NEC					2	4.8	26	2.8			3	1.14	1	0.3	32	9.0
	SIC 9100: Government Fac.			2	30.5	1	0.5	13	8.9	2	0.64	3	0.75			21	41.3
	SIC 9200: Courts/Prisons			2	57.6	3	46.7	6	3.3	2	1.20	2	0.06			15	108.8
	SIC 9700: Military			5	142.2	1	7.2	2	3.3	2	0.40	1	0.06			11	153.2
	Total Commercia	3	85.5	24	633.7	41	607.4	478	246.4	25	11.3	88	14.7	1	0.3	660	1,599.2
	Grand Total	**43**	**1,083.2**	**49**	**3,248.0**	**145**	**3,998.0**	**732**	**445.5**	**34**	**16.6**	**176**	**29.1**	**4**	**8.6**	**1,183**	**8,828.9**

APPENDIX B: Electricity Consumption per Employee Estimates

Industrial

Information on industrial energy use by employee was derived from the 2002 U.S. Census of Manufacturing, available at: http://www.census.gov/econ/census02/guide/INDRPT31.HTM The Census of Manufacturing has information at the six-digit NAICS level of number of establishments, number of employees, and amount of electricity used in kWh. This data was used to calculate the MWh per employee for each industrial application.

Table B-1: Industrial MWh per Employee Figures

NAICS code	MWh Demand/emp
326111	72.1
326112	81.1
326113	102.9
326121	62.6
326122	100.1
326130	43.4
326140	61.0
326150	26.7
326160	160.5
326191	14.2
326192	88.9
326199	42.0
326211	75.7
326212	28.0
326220	40.8
326291	34.8
326299	43.0
327111	31.4
327112	23.4
327113	59.5
327121	67.0
327122	65.8
327123	36.4
327124	38.3
327125	81.4
327211	211.7
327212	125.6
327213	247.7
327215	49.3
327310	688.1
327320	14.5
327331	25.9
327332	15.6
327390	13.1
327410	306.8
327420	194.7
327910	72.5
327991	15.3
327992	159.4
327993	191.8
327999	33.8
331111	456.5
331112	1,087.4
331210	59.4
331221	149.2
331222	76.7
331311	150.3
331312	2,891.8
331314	222.2
331315	209.9
331316	67.8
331319	61.8
331411	248.5
331419	539.9
331421	120.3
331422	67.9
331423	71.9
331491	95.5
331492	76.9
331511	121.4
331512	44.2
331513	198.4
331521	64.6
331522	42.5
331524	46.4
331525	42.4
331528	42.2
332111	60.4
332112	49.5
332114	20.1

NAICS code	MWh Demand/emp
332115	48.7
332116	16.0
332117	51.7
332211	27.8
332212	17.8
332213	26.9
332214	26.5
332311	9.4
332312	13.6
332313	16.8
332321	10.5
332322	9.7
332323	9.0
332410	19.5
332420	15.7
332431	106.3
332439	20.0
332510	14.2
332611	28.4
332612	15.4
332618	16.8
332710	13.8
332721	16.4
332722	23.4
332811	71.3
332812	37.9
332813	29.8
332911	21.8
332912	18.3
332913	26.2
332919	25.3
332991	49.8
332992	30.4
332993	23.7
332994	14.5
332995	22.8
332996	15.6
332997	12.3
332998	24.3
332999	21.5
333111	8.1
333112	7.6
333120	10.7
333131	7.8
333132	11.3
333210	6.3
333220	7.1
333291	6.3
333292	6.9
333293	9.9
333294	5.5
333295	8.7
333298	6.0
333311	5.7
333312	4.9
333313	3.7
333314	7.6
333315	10.2
333319	4.5
333411	5.5
333412	6.9
333414	6.5
333415	8.2
333511	9.3
333512	7.8
333513	6.1
333514	9.0
333515	9.3
333516	11.3
333518	5.5

NAICS code	MWh Demand/emp
333611	10.4
333612	11.8
333613	15.2
333618	18.6
333911	10.7
333912	8.6
333913	8.0
333921	5.6
333922	4.4
333923	5.8
333924	6.1
333991	11.2
333992	13.1
333993	4.8
333994	6.0
333995	10.8
333996	11.2
333997	4.7
333999	6.6
334111	10.7
334112	34.2
334113	27.3
334119	18.1
334210	10.0
334220	13.6
334290	11.1
334310	22.5
334411	64.0
334412	28.8
334413	75.9
334414	39.0
334415	27.7
334416	9.1
334417	18.3
334418	18.6
334419	16.4
334510	13.3
334511	21.9
334512	16.5
334513	13.9
334514	19.3
334515	12.5
334516	10.6
334517	12.6
334518	14.6
334519	14.4
334611	28.4
334612	29.4
334613	50.8
335110	52.3
335121	10.5
335122	14.0
335129	16.1
335211	19.8
335212	26.1
335221	20.8
335222	28.6
335224	29.4
335228	26.9
335311	25.7
335312	23.0
335313	18.3
335314	11.1
335911	91.7
335912	39.2
335921	29.8
335929	49.9
335931	26.0
335932	48.5
335991	131.5

NAICS code	MWh Demand/emp
335999	11.2
336111	34.8
336112	36.6
336120	14.9
336211	9.8
336212	9.8
336213	5.5
336214	5.6
336311	33.6
336312	33.8
336321	26.1
336322	16.1
336330	30.9
336340	29.2
336350	33.8
336360	14.0
336370	23.4
336391	65.2
336399	22.9
336411	12.8
336412	23.0
336413	22.8
336414	13.6
336415	29.1
336419	35.0
336510	13.9
336611	12.1
336612	6.8
336991	14.8
336992	21.3
336999	11.3
337110	11.1
337121	7.9
337122	17.7
337124	12.3
337125	21.3
337127	13.3
337129	17.1
337211	14.8
337212	10.6
337214	19.0
337215	16.1
337910	9.3
337920	8.2
339111	10.7
339112	15.4
339113	14.6
339114	10.7
339115	23.7
339116	4.1
339911	6.2
339912	15.9
339913	6.9
339914	6.3
339920	14.2
339931	7.9
339932	18.8
339941	23.9
339942	22.1
339943	10.4
339944	14.6
339950	9.6
339991	27.2
339992	11.4
339993	40.9
339994	12.7
339995	13.1
339999	11.8

Commercial

Information on commercial electricity use per employee was derived from CEPD and CBECS, and from data in the D&B MarketPlace 2003 database. CEPD and CEBCS were used as control totals while data from the MarketPlace database were used to determine MWh/employee estimates for all facilities with a primary 2-digit SIC from 40 to 97. Some applications were further specialized by using 3-digit SIC codes (421, 422, 423, 541, 542, 543, 545, 551, 554, 555, 701, 702, 703, 801, 805, 806, 807, 821, 822, 823, 832, 836, 921, 9221, 9223, 9224). **Table B-2** shows the final selected values.

Table B-2: Commercial MWh per Employee Figures

SIC Code	NAICS Code	Meaning of NAICS code	MWh Demand/emp
43	491	Postal Service	3.1
52	444	Building Material and Garden Equipment and Supplies Dealers	13.5
4222	49312	Refrigerated Warehousing and Storage	20.2
4581	481	Air Transportation	5.3
4952	221	Utilities	40.0
5411	4451	Grocery Stores	34.4
5812	722	Food Services and Drinking Places	20.3
7011	7211	Traveler Accommodation	22.4
7211	812	Personal and Laundry Services	12.7
7374		Data Centers	14.2
7542	811	Repair and Maintenance	12.7
7832	512	Motion Picture and Sound Recording Industries	8.2
7991	711	Performing Arts, Spectator Sports, and Related Industries	20.0
7997	711	Performing Arts, Spectator Sports, and Related Industries	14.7
8051	623	Nursing and Residential Care Facilities	11.0
8062	622	Hospitals	10.2
8211	6111	Elementary and Secondary Schools	8.5
8221	6112, 6113	Colleges, Universities, and Professional Schools	50.0
8412	712	Museums, Historical Sites, and Similar Institutions	13.1
9100		Government Buildings	8.9
9223	92214	Correctional Institutions	19.1

APPENDIX C: Scenario Results

Base Case

Table C-1: Base Case: Detailed Cumulative Market Penetration by Size, Utility, and Year

Utility Region	50-500 kW	500-1,000 kW	1-5 MW	5-20 MW	>20 MW	All Sizes
2014 Cumulative Market Penetration, MW						
LADWP	0	1	9	10	30	50
SCE	7	20	82	78	46	233
SDG&E	8	7	24	27	18	83
Other South	0	1	7	8	0	16
PG&E	15	12	75	92	23	217
SMUD	0	0	3	6	6	15
Other North	0	0	3	6	0	9
Combined Total	30	41	201	227	123	623
2019 Cumulative Market Penetration, MW						
LADWP	3	8	32	24	58	125
SCE	101	85	286	184	88	743
SDG&E	37	26	79	64	35	241
Other South	4	6	25	19	0	54
PG&E	92	59	274	221	46	692
SMUD	1	2	12	15	11	42
Other North	1	3	11	14	0	28
Combined Total	240	188	718	541	239	1,926
2024 Cumulative Market Penetration, MW						
LADWP	7	13	41	30	65	156
SCE	177	127	369	219	98	990
SDG&E	60	38	102	75	40	313
Other South	9	9	33	23	0	74
PG&E	164	94	365	263	54	939
SMUD	3	4	17	19	13	56
Other North	4	4	14	17	0	40
Combined Total	423	288	941	647	269	2,569
2029 Cumulative Market Penetration, MW						
LADWP	8	14	43	32	67	164
SCE	199	137	385	226	100	1,047
SDG&E	66	40	107	77	41	331
Other South	10	10	34	24	0	78
PG&E	185	103	389	273	57	1,007
SMUD	4	4	18	20	13	60
Other North	4	5	15	19	0	44
Combined Total	476	313	992	671	278	2,731

Table C-2: Base Case: Detailed CHP Outputs and GHG Emissions Savings by Utility and Year

Utility	CHP Market Pen. (MW)	Avoided Elect. for Cooling (MW)	CHP Fuel Use (Billion Btu/year)	Avoided Boiler Fuel (billion Btu/year)	Elect. Generated (million kWh/yr)	Avoided Elect. for cooling (million kWh/yr)	Energy Savings (Billion Btu/yr)	CO2 Savings (1000 Metric Tons)
2014 Outputs and GHG Emissions								
LADWP	50	7	3,645	977	381	29	667	35
SCE	233	20	16,369	5,335	1,632	69	2,709	144
SDG&E	83	10	5,652	1,658	561	33	880	47
Other South	16	1	1,148	391	114	3	168	9
PG&E	217	17	15,609	5,225	1,536	59	2,406	128
SMUD	15	1	1,062	327	110	6	191	10
Other North	9	0	642	246	64	1	114	6
Grand Total	623	57	44,126	14,158	4,398	200	7,135	379
2019 Outputs and GHG Emissions								
LADWP	125	16	8,453	2,297	923	58	1,817	96
SCE	743	64	47,351	14,757	4,990	186	9,523	506
SDG&E	241	27	15,156	4,261	1,596	79	2,892	154
Other South	54	3	3,557	1,168	378	10	676	36
PG&E	692	56	44,839	13,953	4,725	164	8,594	456
SMUD	42	4	2,762	846	303	12	601	32
Other North	28	1	1,874	688	202	2	412	22
Grand Total	1,926	170	123,991	37,971	13,118	511	24,515	1,302
2024 Outputs and GHG Emissions								
LADWP	156	20	10,082	2,714	1,137	65	2,402	128
SCE	990	93	60,557	18,430	6,558	236	13,336	708
SDG&E	313	38	18,976	5,250	2,047	99	3,973	211
Other South	74	5	4,659	1,480	511	13	976	52
PG&E	939	85	58,353	17,786	6,327	217	12,467	662
SMUD	56	5	3,552	1,067	402	15	851	45
Other North	40	1	2,537	907	282	3	607	32
Grand Total	2,569	247	158,716	47,635	17,264	648	34,611	1,838
2029 Outputs and GHG Emissions								
LADWP	164	21	10,573	2,846	1,193	68	2,525	134
SCE	1,047	101	63,849	19,351	6,907	255	14,068	747
SDG&E	331	41	20,033	5,517	2,159	106	4,187	222
Other South	78	5	4,908	1,551	538	14	1,032	55
PG&E	1,007	93	62,390	18,953	6,761	236	13,336	708
SMUD	60	5	3,771	1,133	427	16	907	48
Other North	44	1	2,772	991	308	3	666	35
Grand Total	2,731	267	168,295	50,343	18,293	698	36,722	1,950

Restore SGIP Case

Table C-3: Restore SGIP Case: Detailed Cumulative Market Penetration by Size, Utility, and Year

Utility Region	50-500 kW	500-1,000 kW	1-5 MW	5-20 MW	>20 MW	All Sizes
2014 Cumulative Market Penetration, MW						
LADWP	1	3	12	10	30	56
SCE	29	31	105	78	46	290
SDG&E	11	9	28	27	18	93
Other South	1	2	9	8	0	20
PG&E	31	21	98	92	23	266
SMUD	0	1	5	6	6	17
Other North	1	1	4	6	0	11
Combined Total	74	68	260	227	123	752
2019 Cumulative Market Penetration, MW						
LADWP	9	14	42	24	58	148
SCE	176	128	364	184	88	940
SDG&E	51	35	94	64	35	279
Other South	11	9	32	19	0	71
PG&E	140	94	349	221	46	851
SMUD	3	4	19	15	11	52
Other North	3	5	14	14	0	35
Combined Total	393	290	914	541	239	2,377
2024 Cumulative Market Penetration, MW						
LADWP	13	19	52	30	65	179
SCE	253	171	447	219	98	1,187
SDG&E	74	47	117	75	40	351
Other South	15	13	40	23	0	91
PG&E	211	129	441	263	54	1,098
SMUD	5	6	24	19	13	67
Other North	5	6	18	17	0	47
Combined Total	576	391	1,137	647	269	3,020
2029 Cumulative Market Penetration, MW						
LADWP	14	20	54	32	67	187
SCE	275	180	463	226	100	1,244
SDG&E	80	49	122	77	41	369
Other South	16	14	41	24	0	95
PG&E	233	138	465	273	57	1,166
SMUD	5	7	25	20	13	70
Other North	6	7	19	19	0	51
Combined Total	630	415	1,188	671	278	3,182

Table C-4: Restore SGIP Case: Detailed CHP Outputs and GHG Emissions Savings by Utility and Year

Utility	CHP Market Pen. (MW)	Avoided Elect. for Cooling (MW)	CHP Fuel Use (Billion Btu/year)	Avoided Boiler Fuel (billion Btu/year)	Elect. Generated (million kWh/yr)	Avoided Elect. for cooling (million kWh/yr)	Energy Savings (Billion Btu/yr)	CO2 Savings (1000 Metric Tons)
2014 Outputs and GHG Emissions								
LADWP	56	8	4,012	1,101	417	30	734	39
SCE	290	26	20,013	6,539	1,977	85	3,293	175
SDG&E	93	11	6,307	1,868	623	36	984	52
Other South	20	1	1,414	487	140	4	213	11
PG&E	266	22	18,721	6,214	1,831	73	2,890	153
SMUD	17	2	1,233	385	127	6	221	12
Other North	11	0	772	298	77	1	138	7
Grand Total	752	70	52,471	16,892	5,193	235	8,473	450
2019 Outputs and GHG Emissions								
LADWP	148	18	9,845	2,763	1,066	63	2,117	112
SCE	940	84	59,545	18,912	6,204	233	12,002	637
SDG&E	279	32	17,541	5,066	1,828	91	3,352	178
Other South	71	5	4,649	1,545	489	13	893	47
PG&E	851	72	54,800	17,211	5,708	205	10,439	554
SMUD	52	4	3,370	1,044	367	14	737	39
Other North	35	1	2,346	869	250	2	508	27
Grand Total	2,377	217	152,096	47,411	15,911	622	30,048	1,596
2024 Outputs and Emissions								
LADWP	179	22	11,443	3,136	1,280	70	2,688	143
SCE	1,187	114	72,343	22,075	7,771	280	15,671	832
SDG&E	351	43	21,237	5,905	2,279	109	4,392	233
Other South	91	6	5,723	1,819	621	17	1,180	63
PG&E	1,098	102	67,789	20,563	7,311	254	14,319	760
SMUD	67	6	4,142	1,247	466	17	986	52
Other North	47	1	2,993	1,069	330	3	700	37
Grand Total	3,020	293	185,670	55,814	20,057	750	39,937	2,121
2029 Outputs and GHG Emissions								
LADWP	187	23	11,929	3,267	1,336	73	2,815	150
SCE	1,244	121	75,612	22,993	8,120	299	16,424	872
SDG&E	369	45	22,291	6,172	2,390	116	4,608	245
Other South	95	7	5,969	1,889	649	18	1,239	66
PG&E	1,166	109	71,807	21,727	7,745	273	15,204	807
SMUD	70	6	4,359	1,313	490	18	1,043	55
Other North	51	1	3,226	1,154	356	4	760	40
Grand Total	3,182	314	195,193	58,514	21,086	800	42,093	2,235

CO_2 Payments Case

Table C-5: CO2 Payments Case: Detailed Cumulative Market Penetration by Size, Utility, and Year

Utility Region	50-500 kW	500-1,000 kW	1-5 MW	5-20 MW	>20 MW	All Sizes
2014 Cumulative Market Penetration, MW						
LADWP	0	2	10	11	32	54
SCE	16	23	89	89	51	267
SDG&E	8	7	24	27	19	86
Other South	1	1	7	9	0	18
PG&E	21	15	81	97	26	240
SMUD	0	0	4	7	6	17
Other North	0	1	3	6	0	10
Combined Total	46	49	218	246	133	693
2019 Cumulative Market Penetration, MW						
LADWP	4	10	35	27	61	137
SCE	120	94	308	208	98	829
SDG&E	39	27	82	65	36	250
Other South	6	7	27	21	0	61
PG&E	105	67	295	233	51	751
SMUD	2	2	15	18	12	49
Other North	2	3	12	15	0	32
Combined Total	278	211	774	587	259	2,109
2024 Cumulative Market Penetration, MW						
LADWP	9	15	46	33	68	171
SCE	202	140	396	247	109	1,094
SDG&E	62	39	105	76	41	324
Other South	12	10	35	25	0	82
PG&E	180	104	391	277	59	1,012
SMUD	4	4	21	22	14	65
Other North	4	5	16	19	0	44
Combined Total	474	318	1,010	699	291	2,792
2029 Cumulative Market Penetration, MW						
LADWP	10	17	48	35	70	180
SCE	226	150	413	254	112	1,155
SDG&E	69	42	110	79	42	343
Other South	13	11	37	26	0	86
PG&E	203	114	417	288	62	1,083
SMUD	5	5	22	23	14	70
Other North	5	6	17	21	0	49
Combined Total	532	344	1,064	725	301	2,965

Table C-6: CO2 Payments Case: Detailed CHP Outputs and GHG Emissions Savings by Utility and Year

Utility	CHP Market Pen. (MW)	Avoided Elect. for Cooling (MW)	CHP Fuel Use (Billion Btu/year)	Avoided Boiler Fuel (billion Btu/year)	Elect. Generated (million kWh/yr)	Avoided Elect. for cooling (million kWh/yr)	Energy Savings (Billion Btu/yr)	CO2 Savings (1000 Metric Tons)
2014 Outputs and GHG Emissions								
LADWP	54	8	3,931	1,070	412	30	741	39
SCE	267	22	18,467	6,095	1,857	74	3,251	173
SDG&E	86	10	5,807	1,708	579	33	931	49
Other South	18	1	1,253	430	125	3	196	10
PG&E	240	19	16,912	5,671	1,678	62	2,754	146
SMUD	17	2	1,218	372	127	7	227	12
Other North	10	0	720	276	73	1	135	7
Grand Total	693	61	48,307	15,622	4,853	210	8,235	437
2019 Outputs and GHG Emissions								
LADWP	137	17	9,153	2,520	1,005	60	2,027	108
SCE	829	67	52,202	16,440	5,561	193	11,055	587
SDG&E	250	27	15,577	4,389	1,651	80	3,058	162
Other South	61	4	3,901	1,279	418	10	777	41
PG&E	751	58	47,968	14,968	5,104	169	9,631	511
SMUD	49	4	3,138	951	347	14	709	38
Other North	32	1	2,084	765	227	2	477	25
Grand Total	2,109	178	134,023	41,312	14,313	528	27,735	1,473
2024 Outputs and Emissions								
LADWP	171	21	10,939	2,982	1,239	68	2,668	142
SCE	1,094	98	66,327	20,412	7,239	247	15,212	808
SDG&E	324	39	19,515	5,417	2,115	100	4,181	222
Other South	82	5	5,087	1,617	560	14	1,105	59
PG&E	1,012	89	62,187	19,035	6,790	225	13,756	731
SMUD	65	6	4,010	1,193	455	17	992	53
Other North	44	1	2,799	1,002	313	3	691	37
Grand Total	2,792	259	170,864	51,659	18,712	675	38,605	2,050
2029 Outputs and GHG Emissions								
LADWP	180	22	11,487	3,129	1,301	71	2,809	149
SCE	1,155	106	69,821	21,398	7,613	266	16,019	851
SDG&E	343	42	20,598	5,692	2,230	107	4,406	234
Other South	86	6	5,356	1,694	590	16	1,168	62
PG&E	1,083	97	66,403	20,259	7,247	244	14,696	780
SMUD	70	6	4,259	1,267	484	19	1,057	56
Other North	49	1	3,053	1,093	342	3	756	40
Grand Total	2,965	281	180,976	54,532	19,807	726	40,911	2,173

Expanded Export Case

Table C-7: Expanded Export Case: Detailed Cumulative Market Penetration by Size, Utility, and Year

Utility Region	50-500 kW	500-1,000 kW	1-5 MW	5-20 MW	>20 MW	All Sizes
2014 Cumulative Market Penetration, MW						
LADWP	0	1	9	10	98	118
SCE	8	21	82	78	202	391
SDG&E	8	7	24	27	18	83
Other South	0	1	7	8	0	16
PG&E	15	13	75	92	338	532
SMUD	0	0	3	6	6	15
Other North	0	1	3	6	20	29
Combined Total	31	44	201	227	681	1,184
2019 Cumulative Market Penetration, MW						
LADWP	4	8	32	24	205	273
SCE	102	90	286	184	428	1,089
SDG&E	38	27	79	64	35	243
Other South	5	6	25	19	0	55
PG&E	92	61	274	221	783	1,431
SMUD	1	2	12	15	11	42
Other North	2	3	11	14	47	76
Combined Total	244	196	718	541	1,509	3,209
2024 Cumulative Market Penetration, MW						
LADWP	7	13	41	30	227	319
SCE	178	132	369	219	472	1,371
SDG&E	60	39	102	75	40	314
Other South	10	9	33	23	0	75
PG&E	164	95	365	263	877	1,765
SMUD	3	4	17	19	13	57
Other North	4	5	14	17	56	96
Combined Total	427	297	941	647	1,684	3,996
2029 Cumulative Market Penetration, MW						
LADWP	8	14	43	32	230	328
SCE	201	141	385	226	477	1,430
SDG&E	66	41	107	77	41	332
Other South	11	10	34	24	0	79
PG&E	185	105	389	273	885	1,838
SMUD	4	4	18	20	13	61
Other North	5	5	15	19	60	104
Combined Total	480	321	992	671	1,707	4,172

Table C-8: Expanded Case: Detailed CHP Outputs and GHG Emissions Savings by Utility and Year

Utility	CHP Market Pen. (MW)	Avoided Elect. for Cooling (MW)	CHP Fuel Use (Billion Btu/year)	Avoided Boiler Fuel (billion Btu/year)	Elect. Generated (million kWh/yr)	Avoided Elect. for cooling (million kWh/yr)	Energy Savings (Billion Btu/yr)	CO_2 Savings (1000 Metric Tons)
2014 Outputs and GHG Emissions								
LADWP	118	7	8,683	3,156	927	29	1,882	100
SCE	391	20	28,098	10,409	2,903	69	5,532	294
SDG&E	83	10	5,671	1,667	563	33	883	47
Other South	16	1	1,164	398	115	3	171	9
PG&E	532	17	39,024	15,349	4,075	59	8,056	428
SMUD	15	1	1,070	331	111	6	192	10
Other North	29	0	2,136	893	226	1	474	25
Grand Total	1,184	57	85,846	32,202	8,920	200	17,189	913
2019 Outputs and GHG Emissions								
LADWP	273	16	19,023	6,799	2,114	58	4,635	246
SCE	1,089	64	72,139	25,333	7,777	186	16,098	855
SDG&E	243	27	15,233	4,298	1,604	79	2,905	154
Other South	55	3	3,615	1,195	383	10	686	36
PG&E	1,431	56	97,633	36,433	10,677	164	22,684	1,205
SMUD	42	4	2,794	861	306	12	606	32
Other North	76	1	5,248	2,125	582	2	1,309	69
Grand Total	3,209	170	215,685	77,043	23,443	511	48,922	2,598
2024 Outputs and Emissions								
LADWP	319	20	21,368	7,461	2,449	65	5,651	300
SCE	1,371	93	86,963	29,532	9,623	236	20,901	1,110
SDG&E	314	38	19,046	5,279	2,055	99	3,985	212
Other South	75	5	4,714	1,504	516	13	985	52
PG&E	1,765	85	115,509	41,823	12,975	217	28,941	1,537
SMUD	57	5	3,582	1,080	405	15	856	45
Other North	96	1	6,434	2,547	735	3	1,727	92
Grand Total	3,996	247	257,617	89,225	28,758	648	63,046	3,348
2029 Outputs and GHG Emissions								
LADWP	328	21	21,924	7,620	2,513	68	5,794	308
SCE	1,430	101	90,405	30,516	9,990	255	21,677	1,151
SDG&E	332	41	20,103	5,545	2,166	106	4,199	223
Other South	79	5	4,962	1,575	543	14	1,041	55
PG&E	1,838	93	119,929	43,151	13,454	236	29,922	1,589
SMUD	61	5	3,801	1,146	430	16	912	48
Other North	104	1	6,971	2,758	796	3	1,873	99
Grand Total	4,172	267	268,094	92,311	29,892	698	65,418	3,474

"All-In" Case

Table C-9: All-In Case: Detailed Cumulative Market Penetration by Size, Utility, and Year

Utility Region	50-500 kW	500-1,000 kW	1-5 MW	5-20 MW	>20 MW	All Sizes
2014 Cumulative Market Penetration, MW						
LADWP	1	4	13	11	159	188
SCE	34	36	113	94	345	622
SDG&E	12	10	29	29	19	98
Other South	1	3	10	10	0	24
PG&E	34	25	106	102	863	1,130
SMUD	1	1	6	8	6	22
Other North	1	1	4	7	40	53
Combined Total	83	78	282	261	1,432	2,136
2019 Cumulative Market Penetration, MW						
LADWP	12	16	47	27	305	407
SCE	193	141	389	220	663	1,607
SDG&E	54	37	98	70	36	294
Other South	13	11	36	24	0	83
PG&E	149	104	378	244	1,664	2,538
SMUD	3	5	22	21	12	63
Other North	4	5	15	16	81	123
Combined Total	428	319	985	621	2,762	5,115
2024 Cumulative Market Penetration, MW						
LADWP	17	22	57	33	331	460
SCE	276	187	478	260	716	1,917
SDG&E	77	49	121	81	41	369
Other South	18	14	44	28	0	105
PG&E	225	141	476	289	1,793	2,925
SMUD	6	8	28	25	14	80
Other North	7	7	19	21	93	147
Combined Total	625	428	1,224	738	2,988	6,003
2029 Cumulative Market Penetration, MW						
LADWP	18	23	59	35	334	470
SCE	300	197	495	267	722	1,982
SDG&E	84	52	127	84	42	388
Other South	19	15	46	29	0	110
PG&E	247	151	502	300	1,804	3,004
SMUD	7	8	29	27	14	85
Other North	8	8	21	22	98	157
Combined Total	684	454	1,279	764	3,015	6,195

Table C-10: All-In Case: Detailed CHP Outputs and GHG Emissions Savings by Utility and Year

Utility	CHP Market Pen. (MW)	Avoided Elect. for Cooling (MW)	CHP Fuel Use (Billion Btu/year)	Avoided Boiler Fuel (billion Btu/year)	Elect. Generated (million kWh/yr)	Avoided Elect. for cooling (million kWh/yr)	Energy Savings (Billion Btu/yr)	CO_2 Savings (1000 Metric Tons)
2014 Outputs and GHG Emissions								
LADWP	188	8	13,776	5,295	1,476	31	3,094	164
SCE	622	27	44,261	16,905	4,609	87	9,191	488
SDG&E	98	11	6,638	1,990	661	36	1,073	57
Other South	24	1	1,673	588	168	4	269	14
PG&E	1,130	23	82,591	33,731	8,765	74	18,350	975
SMUD	22	2	1,497	475	156	7	280	15
Other North	53	0	3,885	1,639	415	1	889	47
Grand Total	2,136	73	154,322	60,623	16,249	241	33,146	1,760
2019 Outputs and GHG Emissions								
LADWP	407	19	28,153	10,477	3,133	65	7,025	373
SCE	1,607	87	105,842	38,277	11,449	239	24,603	1,307
SDG&E	294	32	18,367	5,357	1,928	92	3,617	192
Other South	83	5	5,337	1,796	567	14	1,072	57
PG&E	2,538	74	174,221	67,751	19,210	208	42,549	2,260
SMUD	63	5	4,016	1,253	441	16	910	48
Other North	123	1	8,526	3,480	947	3	2,159	115
Grand Total	5,115	223	344,462	128,391	37,673	637	81,934	4,351
2024 Outputs and Emissions								
LADWP	460	23	30,662	11,119	3,517	73	8,249	438
SCE	1,917	117	121,345	42,245	13,494	289	30,054	1,596
SDG&E	369	43	22,202	6,237	2,398	110	4,718	251
Other South	105	7	6,527	2,101	715	18	1,406	75
PG&E	2,925	105	192,954	72,826	21,904	260	50,649	2,690
SMUD	80	7	4,891	1,482	554	19	1,205	64
Other North	147	2	9,851	3,929	1,128	4	2,680	142
Grand Total	6,003	304	388,431	139,939	43,710	773	98,961	5,255
2029 Outputs and GHG Emissions								
LADWP	470	25	31,291	11,301	3,590	76	8,416	447
SCE	1,982	125	125,038	43,321	13,893	308	30,940	1,643
SDG&E	388	46	23,288	6,514	2,513	117	4,948	263
Other South	110	7	6,802	2,181	746	19	1,473	78
PG&E	3,004	112	197,739	74,290	22,430	279	51,770	2,749
SMUD	85	7	5,147	1,559	583	20	1,274	68
Other North	157	2	10,483	4,180	1,200	4	2,855	152
Grand Total	6,195	325	399,788	143,346	44,955	824	101,675	5,400

APPENDIX D: Comparison to 2005 Market Study

This CHP market assessment is based on a framework developed in two previous studies for the Energy Commission. These previous studies and the current study were all conducted by the same project team. The first study conducted in 1999[34] identified the CHP market opportunity to be over 12,000 MW of technical potential and an estimated 4,000 MW of economic market potential over the 2002-2020 forecast period. The second study conducted in 2005[35] identified 28,000 MW of CHP technical potential and contained market scenarios with from 1,900 MW to 7,300 MW of market penetration by 2020.

Similar to the current study, the 2005 study was undertaken to provide input to the *Integrated Energy Policy Report* (*IEPR 2005*). The focus of the 2005 study was to:

- Quantify and update the technical and economic potential for CHP in California, last undertaken in 1999.
- Assess the end-user adoption barriers to CHP.
- Develop approaches for incentives and other options to realize the CHP opportunity.
- Assess the technology gaps and R&D needs to move the CHP market opportunity forward.

The 2005 study was referenced in the development of the AB 1613 CHP export program and in the development of CHP market targets for the *Climate Scoping Plan*. In undertaking the 2009 study, the study team used the same approach to developing technical potential and market penetration; however several of the input data elements were refined to provide for a more accurate analysis.

Comparison of Technical Market Potential

For 2009, the study team substantially revised its approach to the quantification of technical market potential, as shown in **Table D-1.** The changes included:

- Use of a more detailed database of California industrial and commercial facilities, which contains business information, such as number of employees, in exact figures rather than ranges.
- A more detailed approach to developing site electric and thermal loads that can be met by CHP, including an evaluation of load estimates specific to California.
- A reduction in the application-specific growth rates for new and expanded facilities over the forecast period, due to changes in economic conditions.

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34 *Market Assessment of Combined Heat and Power in the State of California*, prepared by Onsite Sycom Energy Corporation, California Energy Commission Report P700-00-009, July 1999 (released October 2000.)

35 *Assessment of CHP Market and Policy Options for Increased Penetration*, April 2005. EPRI, CEC-500-2005-060-D.

- The addition of export potential in facilities with technical potential below 20 MW; these facilities were added to measure the potential impacts of AB 1613.

Overall, the reported technical market potential for CHP decreased by about 10,000 MW between the 2005 study and the 2009 study. Half of this decrease is due to a reduction in projected economic growth in the state over the time period of the studies; the remainder is due to the use of more accurate facilities data and improvements to the approach used to estimate electricity and thermal loads in target applications. The project team believes that this current study more accurately represents the potential CHP market. The refined technical potential figures in the 2009 study allowed for simplifying the market penetration model to remove maximum market penetration factors that restricted the market due to the uncertainty in the previous technical potential estimates. The overall impact of these changes is a more realistic representation of the potential market for CHP in California.

Table D-1: 2005 to 2009 CHP Technical Potential Estimation

2009 v 2005 Changes	2005 study	2009 study	Gross Change MW	Rationale
Onsite Markets Existing Customers	17,294	11,527	(5,767)	Updated and more accurate site databases, revised estimates of thermal and electric loads based on California and CHP matching
Export Markets Existing	3,895	4,544	649	Addition of <20 MW sizes to the export market
Onsite Markets New	7,055	2,049	(5,006)	Reduced economic growth forecasts
Export Markets New	194	297	103	Addition of <20 MW sizes to the export market
Net Change	28,438	18,417	(10,021)	New results matched with Calif. State consumption values

Source: EPRI 2005 Market Study and ICF International, Inc.

Comparison of Energy Price Assumptions

Both natural gas and electric prices are lower in real terms in the 2009 study than in the 2005 study as shown in **Figure D-1**. Not only are prices considerably lower today than in 2005, the forecast prices for the first five years of the 2009 forecast average 24% lower than in 2005, and forecast prices in the second five years average 16% lower. The 2009 forecast prices beyond 2020, not included in the 2005 study, appear consistent with an extension of the 2005 forecast out-year price trends.

Figure D-2 shows the comparison of the portion of electric rates that can be avoided by operating baseload CHP for on-site use. Again, in real dollars, average prices are lower in 2009 than in 2005. At the start of the 2009 forecast period, the 2009 electric prices are 20-23 percent lower than the 2005 price estimates. The price gap narrows by 2020 for commercial sized

customers and disappears in the large industrial market. The ratio of electric prices to gas prices is similar in both studies.

Overall, the combined effect of the gas and electric price forecasts is to provide a somewhat more attractive economic environment for CHP in the 2009 study than that in the 2005 study.

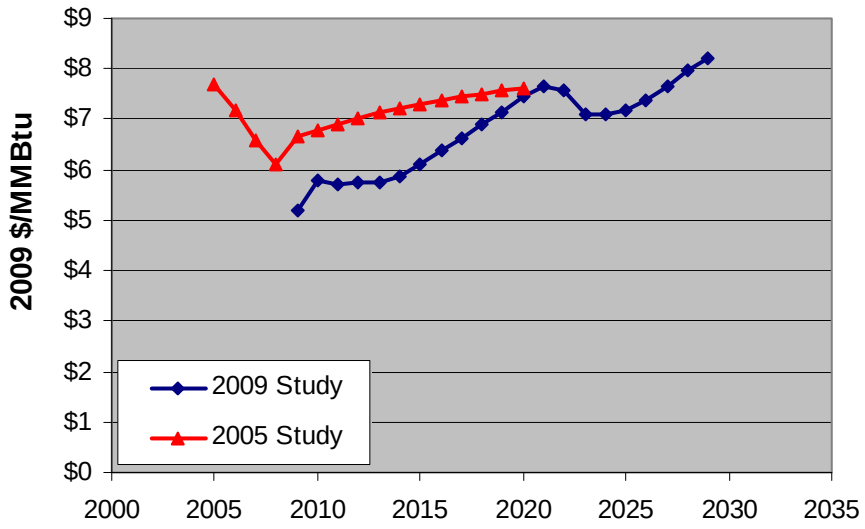

Figure D-1: Comparison of 2005-2009 Natural Gas Prices for Electricity Generation

Source: Adapted from EIA 2005 and 2009 Annual Energy Outlook

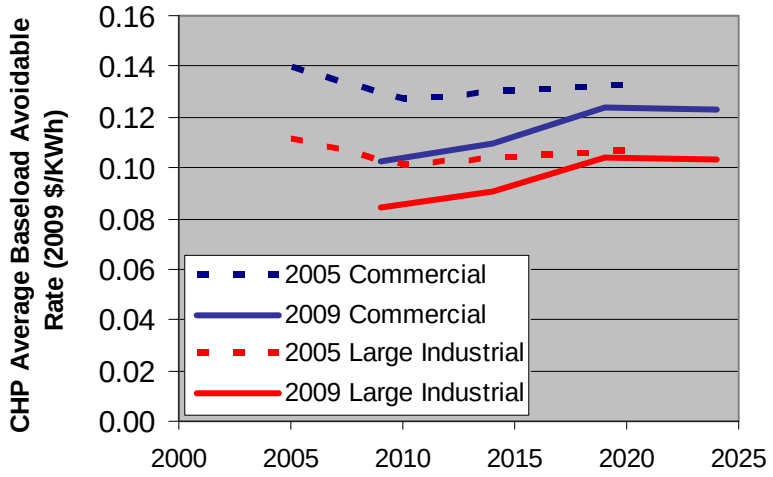

Figure D-2: 2005-2009 Comparison of Electric Price Forecasts

Source: ICF International

CHP Technology Capital Costs

CHP capital costs have increased between 2005 and 2009 as shown in **Table D-2.** The table includes the 10% federal investment tax credit for CHP equipment that was not available in 2005 but was included in the 2009 study. Although some technologies have shown a price decrease, for the most part, capital costs have increased for CHP systems in the last four years at a rate faster than inflation, which was 10% over the same period.

Table D-2: Study Assumptions: CHP Capital Cost Increases 2005-2009

CHP Market Size	CHP Technology	2009-2005 Net Capital Cost Change
50-500 kW	100 kW ICE 65 kW MT 200 kW PAFC	29% 22% 38%
500-1,000 kW	800 kW ICE 250 kW MT x 3 300 kW MCFC x 2	56% 18% -22%
1-5 MW	3000 kW ICE 3000 kW GT 1500 kW MCFC	-2% 13% 10%
5-20 MW	5 MW ICE 10 MW GT	10% 21%
>20 MW	40 MW GT	25%

Abbreviations
ICE = Internal combustion engine
MT = Microturbine
PAFC = phosphoric acid fuel cell
MCFC = molten carbonate fuel cell
GT = gas turbine

Source: ICF International

Scenario Results

Both the 2005 and 2009 CHP market assessments looked at a Base Case forecast and a number of alternative cases testing different incentive measures designed to stimulate CHP market penetration. Both studies looked at the impacts of the self-generation incentive program (SGIP), payments for CO_2 emissions reductions, and improved access and pricing for export markets. Both studies also explored changes in customer acceptance rates for various payback periods. However, in the 2005 study, a general increase in market acceptance rates was modeled to reflect the positive effects of education, promotion, and higher marketing effort stimulated by other market incentives. In the 2009 study, higher acceptance rates were used in the large export market only to reflect the customer attitudes in that market today, not as a result of external market stimulus.

Figure D-3 compares the market penetration forecasts for CHP market penetration with SGIP. This scenario was the Base Case in 2005 because the SGIP incentives for all types of small CHP were still active. In 2009, this case was an incentive case, reflecting the fact that SGIP is not currently active for any technologies other than fuel cells. The actual 2005-2008 market

penetration is shown to the left of the diamond on the 2009 forecast line. During this 4-year period, 185 MW of new CHP entered the market. The 2005-2010 market penetration forecast for this case was 234 MW. The first five years of the 2009 forecast is nearly identical to the 2005 forecast, after which the 2009 forecast is about 500 MW higher by 2020. The additional market penetration is the result of both the more favorable energy prices and the fact that the SGIP program was assumed to remain in effect until 2019 in the 2009 forecast and only 2015 in the 2005 forecast. (Both studies assumed that the program would be in effect for ten years from the starting point of the forecast.)

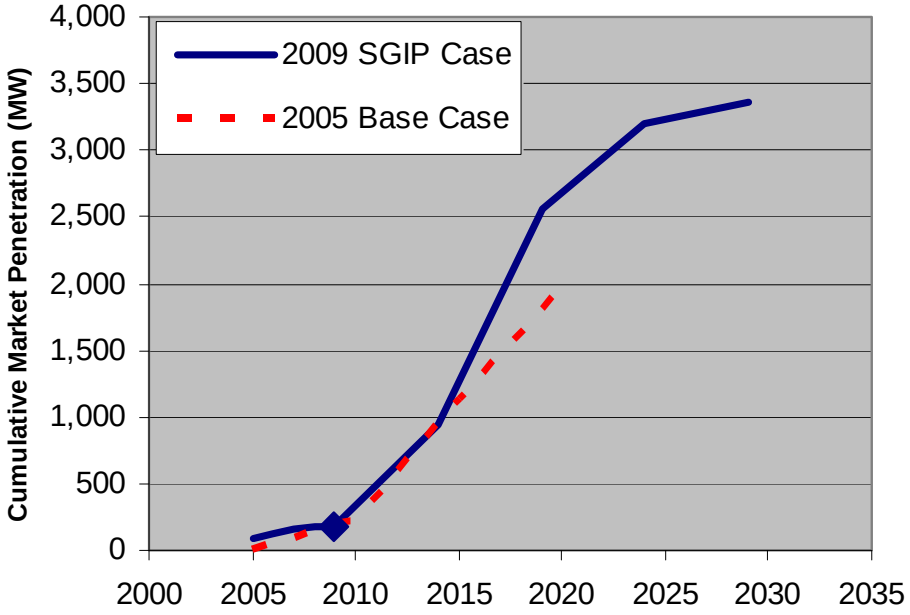

Figure D-3: Comparison of 2005 and 2009 Forecasts With SGIP in Effect

Source: ICF International

Encouraging the large export market was a major factor in both studies of increasing market penetration for CHP. In the 2005 study 2,400-2,900 MW of export CHP was forecast to enter the market between 2005 and 2020. In the 2009 study, stimulation of this market provides 1,400-2,800 MW of export CHP between 2009 and 2020. **Figure D-4** shows that the 2005 and 2009 large export scenarios differ primarily in that the 2005 case assumed that large export market access would become available immediately. Since this was not the case, the export growth in 2009 case is not assumed to begin until 2009. The two cases show a very similar growth rate for the period of large export market access.

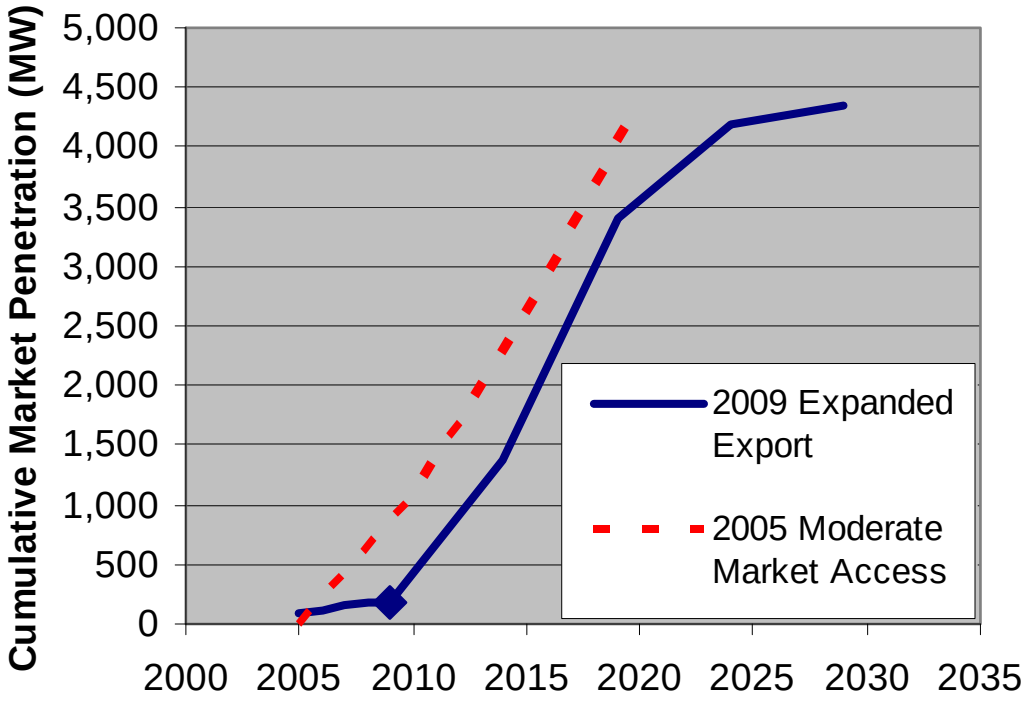

Figure D-4: Comparison of 2005 and 2009 Scenarios With Large Export Stimulation

Source: ICF International

The 2005 study looked at the impacts of incentive measures that were not included in the 2009 study. These measures included $40/kW-year capacity payments to CHP projects for transmission and distribution support and $0.01/kWh production tax credits. Either or both of these measures could be added to the 2009 All-In Case and result in higher market penetrations than were shown with the measures that were included. In the 2005 study these measures added 800-900 MW of market penetration each. However, there was a determination made during the course of the 2005 study that these two incentives are alternative ways to account for the same benefit, so one or the other might be implemented, but not both.

APPENDIX E: Biogas and Waste Heat CHP Applications

This report describes the market size and potential market penetration of natural gas fueled CHP in California. Natural gas-based CHP systems are primarily topping cycles in which the input fuel, natural gas, is used in a prime mover such as a gas turbine, reciprocating engine, microturbine, or fuel cell, for electricity production and a portion of the heat normally wasted is recovered to supply thermal needs such as process steam or space cooling at the site. Natural gas is by far the predominant fuel used for CHP in California, representing 84% of the 8,829 MW of installed CHP capacity in the state. Natural gas is the fuel of choice for most CHP applications because of its competitive price, ease of use, reliability of supply, relatively low criteria pollutant emissions, and, increasingly, its low carbon content in comparison to coal and oil. If properly designed and operated, natural gas CHP can provide significant benefits to California in terms of energy efficiency and reduced CO_2 emissions.

Many policy makers are also interested in promoting CHP fueled by renewable fuels or waste heat. Renewable-fueled CHP is often based on topping cycles in which fuels such as anaerobic digester gas are used in place of natural gas to fuel the prime mover. Waste heat CHP systems are bottoming cycles in which fuel is first used to produce useful thermal energy for a process and energy is recovered from the hot exhaust for electricity production. Both approaches provide additional CO_2 reduction benefits. Biogas is generally considered to be a carbon-neutral source of energy because the carbon emitted during combustion is atmospheric carbon that was recently fixed by plants or other organisms, as opposed to the combustion of fossil fuels where carbon sequestered for millions of years is released into the atmosphere. Waste heat CHP provides electricity with essentially zero carbon emissions as long as there is no supplemental fuel used in the conversion process. This section provides a description and preliminary estimates of market potential in California for three low-carbon CHP options.

Anaerobic Digestion – Municipal Wastewater Treatment[36]

Wastewater treatment plants are an essential and integral part of all urban communities in the Unites States. These plants routinely process residential, commercial, and industrial wastes for conversion into benign liquid and solid waste streams. Many wastewater treatment facilities employ anaerobic digesters to break down sewage sludge and eliminate pathogens in wastewater. During the wastewater treatment process, solids from primary and secondary treatment are collected and further processed, via digestion, to stabilize and reduce the volume of the sludge. The digestion is typically performed anaerobically in which bacteria break down the organic matter in an oxygen-free environment. Most anaerobic digesters are heated to accelerate the digestion process. The process produces a biogas consisting of 65-70% methane, 30% carbon dioxide, and other inert gases such as nitrogen. Most wastewater treatment plants that utilize anaerobic digestion collect and use their biogas on-site to provide heating for the digester itself and space heating for the facility. Some municipalities have begun to divert food

36 Wastewater Treatment analysis based on California Energy Commission Staff Paper, *Combined Heat and Power at California's Wastewater Treatment Plants,* Pramod Kulkani, September 2009.

waste from landfills to wastewater treatment plants; this relieves waste burdens placed on local landfills and allows for increased biogas production from the digester.

The biogas can also be used to fuel CHP systems driven by reciprocating engines, gas turbines, microturbines, or fuel cells. The power generated can be used on-site or sold into the grid, and the thermal output of the system is used to heat the digester and provide space and process heating to the wastewater treatment facility. The heat content of the gas is typically 400 to 600 Btu/standard cubic feet[37]. Biogases are produced at near-atmospheric pressure, so they must be compressed for delivery to the engine or turbine. The fuel is generally treated to remove moisture, siloxanes, and sometimes hydrogen sulfide. Fuel treatment systems consist of chillers, moisture separators, siloxane removal vessels, heat exchangers, blowers, and associated connections. After compression, cooling and scrubbing (or filtration) are required to remove compressor oil, condensate, and particulates that may have been entrained in the original gas.

There are 268 wastewater treatment plants in California that have discharge capacity of 1 million gallons per day or more – considered the minimum size for economical CHP. One hundred and seventeen of these currently have anaerobic digesters. These facilities represent approximately 125 MW of digester-based CHP capacity. Approximately 30 to 35 MW of digester-based CHP is currently in place[38], leaving 90 to 95 MW of unmet potential CHP capacity. Co-digestion of restaurant fat and grease and food processing waste would add an additional 105 MW of potential CHP capacity.

Anaerobic Digestion – Livestock Operations

Animal production operations use anaerobic digestion to reduce the solids content of manure and to improve its quality. Digesters are increasingly used to reduce the volume of manure waste, reduce odor, lower disposal traffic and costs, reduce spreading disposal costs, enhance pathogen control and destruction, and protect the groundwater. Along with biogas, the byproducts of the digester system also include a high-quality compost that can be used for crop fertilizer. Digesters are most suitable for operations that handle large amounts of manure as a liquid, slurry, or semi-solid with little or no bedding added. Because the vast majority of large dairy and swine operations use liquid or slurry manure management systems, biogas production potential is very significant at these operations. The type of digester is typically matched to the type, design, and manure characteristics of the operation. There are three types of digester systems: covered lagoon (used to treat liquid manure), complete mix digester (heated engineered tanks for scraped and flushed manure), and plug flow (treated scraped dairy manure in the 11 to 13% solids range). Swine manure does not have enough fiber to treat in a plug flow digester. Biogas from a manure digester typically contains 60 to 70% methane, depending on the type of animal and the manure collection system. The balance of the biogas is composed of carbon dioxide and trace amounts of hydrogen sulfide.

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37 Natural gas has approximately 1,020 Btu per standard cubic feet.

38 There is 171.5 MW of existing CHP capacity at wastewater treatment plants in California. Much of this, however, is fired by natural gas.

The amount of methane generated by animal type and digestion method has been estimated based on data collected from digester systems participating in EPA's AgSTAR program, as presented in **Table E-1**. The actual methane generation rate will vary significantly from site to site, due to variables such as digester design, animal diet and weight, and local climatological conditions.

Table E-1: Anaerobic Digestion Methane Generation by Animal Type[39]

Animal Group	Animal Type	Methane Generation (cubic feet/head-day)
Dairy	Dairy Calf	38.50
Dairy	Dairy Cow: Dry	38.50
Dairy	Dairy Cow: Lactating	38.50
Dairy	Dairy Heifer	38.50
Swine	Feeder Pigs	4.40
Swine	Nursing Pigs	1.30
Swine	Sow: Gestating	6.10
Swine	Sow: Lactating	6.10
Swine	Weaned Pigs	1.30

Source: Adapted from EPA

The use of manure biogas CHP is limited to farms that have the animals and manure management to accommodate anaerobic digestion. Operations that produce electricity from biogas may sell much of the electricity back to the grid. Thermal energy is used to heat the digesters and for process use at the facility. As digester system size increases, the unit costs for construction and operation decrease significantly. EPA has identified dairy operations with a milking herd of more than 500 cows and swine operations with more than 2,000 head of confinement capacity as the animal operations most likely to profit from anaerobic manure digestion[39].

The primary opportunity for manure biogas CHP in California is in the dairy industry. EPA estimated in 2004 that California has about 1,000 dairies with more than 500 cows, encompassing almost 1.3 million head. These facilities represent 200 to 250 MW of CHP capacity if all sites incorporated anaerobic digesters into their operations.

39 US EPA, *Market Opportunities for Biogas Recovery Systems, A Guide to Identifying Candidates for On-Farm and Centralized Systems*. EPA-430-8-06-004. Available on-line at: http://www.epa.gov/agstar/pdf/biogas%20recovery%20systems_screenres.pdf

Waste Heat to Power

Roughly a third of the energy consumed by the U.S. manufacturing industry is discharged as thermal losses to the atmosphere or to cooling systems[40]. These discharges are the result of process inefficiencies and the inability of the manufacturer to utilize the excess energy streams. Nationally, this waste energy is estimated to be over 10 quads per year (1 quad = 10^{15} Btu)[40]. Most of this waste energy, however, is low quality (i.e., below 500° F) and not practical or economical to recover. Estimates of the amount of the waste heat considered high enough in temperature and quality to represent an opportunity for waste heat recovery for power range from 0.5 to 1.8 quads on a national basis (4,000 to 14,000 MW electric capacity assuming 20% conversion efficiency and 7,500 hours per year operation)[41,42].

Waste heat CHP systems are bottoming cycles in which energy recovered from the hot exhaust is converted to electricity through a Rankine power cycle as shown in **Figure E-1.** Power produced by such a heat recovery system could be used internally at the site and any excess sold into the electric grid.

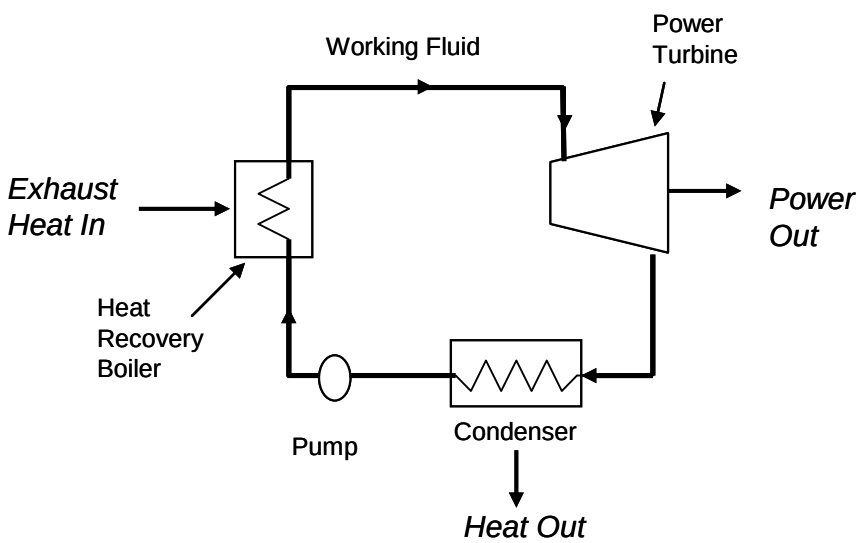

Figure E-1: Waste Heat Recovery Power Cycle

Source: ICF International

In a heat recovery Rankine cycle, a working fluid is first pumped to elevated pressure before entering a heat recovery boiler. The pressurized fluid is vaporized by the hot exhaust, and then expanded to lower pressure in a turbine, generating mechanical power that can drive an electric generator. The low-pressure vapor is then exhausted to a condenser at vacuum conditions

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40 *Engineering Scoping Study of Thermoelectric Generator Systems for Industrial Waste Heat Recovery*, Terry Hendricks, Pacific Northwest National Laboratory, William Choate, BCS Incorporated, Report to U.S. DOE Industrial Technologies Program, November 2006.

41 *Inventory of Industrial Waste Heat Opportunities and Opportunities for Thermally Activated Technologies*, United Technologies Research Center, Draft report to Oak Ridge National Laboratory, April 2004.

42 *Energy Use, Loss and Opportunity Analysis: U.S. Manufacturing and Mining*, Energetics, Inc., E3M, Incorporated, Report to U.S. DOE Industrial Technologies Program, December 2004

where heat is removed condensing the vapor back into a liquid. The condensate is returned to the pump for continuation of the cycle. This is the same cycle used in a conventional power plant based on steam. Water is typically used in heat recovery cycles, but the lower temperatures often found in heat recovery applications require that other working fluids to be used. A system that uses a hydrocarbon as the working fluid is referred to as an organic Rankine cycle (ORC). ORCs are based on the cycle outlined in **Figure E-1** and include similar but slightly different components including a vaporizer, preheater, condenser and recuperator. There are numerous examples of both steam cycles and ORCs being used to generate power from waste heat or from low to medium temperature energy sources. Steam cycles are often used in industrial applications to generate power from operations with hot exhaust gases such as coke oven batteries and cement kilns. ORCs are commonly used to generate power in geothermal power plants, and more recently, in pipeline compressor heat recovery applications. Waste heat to power projects are difficult to justify for low (~500°F or lower) temperature waste heat, especially if the waste heat supply is not continuous and auxiliary energy is required.

Manufacturing industries with high-quality waste heat that could provide potential waste heat to power opportunities include:

- NAICS 324 Petroleum and Coal Product Manufacturing – Petroleum and coal product manufacturing includes the production of refined end-use products, such as gasoline, kerosene, and propane, as well as the production of feedstocks used in other industries, such as chemical manufacturing and rubber and plastics manufacturing. Basis processes used in petroleum refineries include distillation processes (fractionation), thermal cracking processes, catalytic processes, and treatment processes. Although these processes use large amounts of energy, modern refineries use heat produced in exothermic reactions for heating other processes, resulting in integrated heat recovery systems for process use. Many exhaust streams still contain high-quality waste heat that could be recovered for power production. An example is the exhaust from petroleum coke calciners. Petroleum coke is heated to 2400°F; the exhaust leaving the calciner is typically 900°F to 1,000°F.
- NAICS 325 Chemical Manufacturing - The chemical industry is the largest consumer of energy in the United States according to the 1998 Manufacturing Energy Consumption Survey, accounting for 3.7 quads of energy usage. It has numerous processes with the potential to emit significant amounts of waste heat. The United States chemical industry is also extremely diverse, producing on the order of 70,000 products (Energetics, 2000). There are several major sectors of the industry, including petrochemicals, industrial gases, alkalies and chlorine, cyclic crudes and intermediates (e.g., ethylene, propylene, and benzene/toluene/xylene), plastics materials, synthetic rubber, synthetic organic fibers, and agricultural chemicals (fertilizers and pesticides) in which high temperature exhaust is released that could be recovered for power generation.
- NAICS 327 Non-Metallic Mineral Product Manufacturing – The non-metallic mineral products industries, which include cement manufacturing, glass and glass products manufacturing, clay tile and brick material manufacturing, are large consumers of

energy. As an example, the cement industry uses large rotary kilns operated at temperatures close to 2000°F to produce clinker. More generically, this is a calcining process, also used to produce gypsum, alumina, soda ash, lime, and kaolin clay. The glass industry uses raw material melting furnaces, annealing ovens, and tempering furnaces, all operated at high temperatures. Modern glass factories use regenerative furnaces to maintain high energy efficiency. In addition, electric boosting is used increasingly on furnaces to improve efficiency and yield, and oxy-fuel firing reduces energy usage and increases efficiency. Clay building products are fired in high-temperature kilns. Clay firing employs tunnel kilns and periodic kilns, depending on the product being produced. Periodic kilns do not represent a good opportunity for heat recovery for power due to their intermittent operation, but tunnel kilns are steadier in output and could provide an economic application.

- NAICS 331 Primary Metal Manufacturing – Metal foundries contain a variety of waste heat sources, such as melting furnace exhaust, ladle preheating, core baking, pouring, shot-blasting, castings cooling, heat treating, and quenching. The highest temperature waste heat sources are the off gases from melting and heat-treating furnaces. The exhaust from the heat-treating furnaces is the cleanest steady temperature source, free of particulates and corrosives. Pouring and core baking are also high-temperature waste heat sources, but economic utilization is difficult because of either the intermittent nature of waste heat generation or the relatively small streams.
- NAICS 332-336 - Metal-based Durable Industries – NAICS codes 332 through 336 include the following industry classes:
    - Fabricated metal product manufacturing (332)
    - Machinery manufacturing (333)
    - Computer and electronic product manufacturing (334)
    - Electrical equipment manufacturing (335)
    - Transportation equipment manufacturing (336)

  Processes generating waste heat include metal preheating, heat treatment, cleaning, drying, and furnace heating.

Determining the waste heat to power potential in any of these industries can be an involved process. The applicability of waste recovery for power depends on many site-specific issues beyond just exhaust temperatures and flows, including whether the heat is continuous, cyclic, or intermittent, whether the temperature and flow rate is constant or variable with time, whether the exhaust is contaminated with particulates, moisture, corrosive gases or condensables, whether the exhaust is at positive or negative pressure, and whether or not there is existing stack clean-up equipment. Many hot exhaust streams are diluted with air shortly after leaving the process and before entering clean-up equipment, reducing temperature and making waste heat to power impractical unless extensive modifications are made to existing practice.

The cement industry is a particularly good candidate for waste heat CHP. Cement is a combination of calcium, silicon, aluminum, and iron. In the United States, cement is produced in a rotary kiln process (**Figure E-2**), where the mixture of raw materials is fed into the upper end of large cylindrical, refractory-lined steel kilns that range from 60 to 300 meters long and from over 3 to 8 meters in diameter. The blended mixture is fed into the upper end of the tilted kiln at a rate controlled by the slope and rotational speed of the kiln. Fuel is fed into the lower end of the kiln. As the kiln slowly rotates (1 to 4 revolutions per minute), the raw material tumbles through progressively hotter zones toward the flame at the lower end of the kiln. Hot exhaust exits through the top of the kiln and is used to preheat or precalcine raw material feed before it enters the kiln. Clinker is discharged red-hot from the lower end of the kiln and transferred to coolers to lower the clinker to handling temperatures. Cooled clinker is combined with gypsum and other additives and ground into a fine gray powder called cement.

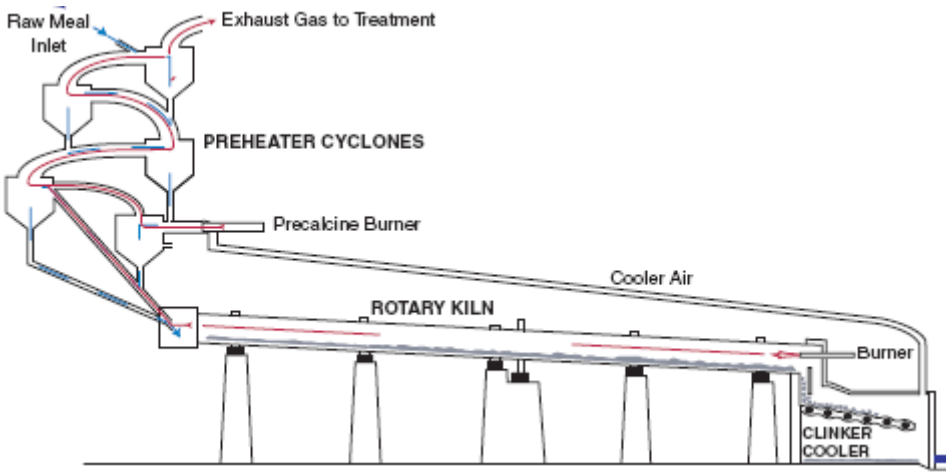

Figure E-2: Rotary Cement Kiln

Source: *Energy and Emissions Reduction Opportunities for the Cement Industry*, U.S. DOE, December 2003

The exhaust streams from the kiln, both from the clinker cooler and the kiln preheater system, all contain useful thermal energy that can be converted into power. The clinker coolers typically release large amounts of heated air at 550°F to 650°F directly into the atmosphere. At the kiln charging side, a large portion of the 620°F to 700°F kiln gas coming off of the preheaters is typically cooled with a water spray before entering electrostatic precipitators to remove dust before being vented to the atmosphere. **Figure E-3** illustrates a typical waste heat CHP system that is applied to rotary cement kilns around the world. Waste heat boilers are installed on the hot exhaust streams exiting the preheaters and air quench clinker cooler to produce medium/low pressure steam. The steam is fed into a condensing steam turbine that drives a generator to produce power. Hot condensate from the condenser is fed back to the waste heat boilers.

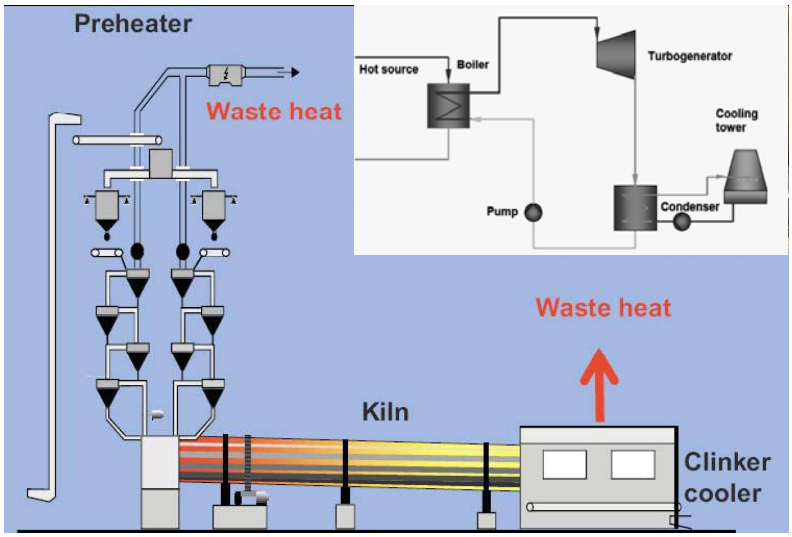

Figure E-3: Waste Heat Recovery System
Source: E3M, Incorporated

The high-efficiency heat recovery design shown in **Figure E-3** can produce approximately 9 MW for a 4,500 ton per day clinker line. According to the Portland Cement Association[43], California had 37,364 tons per day of operating clinker capacity in 2006, which represent about 75 MW of waste heat CHP capacity.

It was beyond the objectives of this study to evaluate the total waste heat CHP potential in California industry in detail. An approximation can be developed, however, by prorating the national estimate of 4,000 to 14,000 MW described above by the percentage of industrial energy consumption represented by California, which was 6.0% for 2007[44]. This results in a range of potential waste heat CHP in California industry of 240 to 840 MW.

43 *U.S. and Canadian Portland Cement Plant Information Summary*, Portland Cement Association, December 31, 2006.
44 EIA State Energy Data System (SEDS), Industrial Energy Consumption 2007, http://www.eia.doe.gov/emeu/states/sep_sum/html/pdf/sum_btu_ind.pdf

Summary

A partial list of the potential for anaerobic digester gas (ADG) and waste heat CHP in California is shown in **Table E-2.**

Table E-2: Anaerobic Digester and Waste Heat CHP Potential

	Potential, MW
Wastewater Treatment ADG CHP	95 - 200
Livestock ADG CHP	200 - 250
Industrial Waste Heat CHP	240 - 840

Source: ICF International

Robust development of these markets is unlikely without further technology demonstration and regulatory and policy support similar to the options discussed in this report for natural gas-based CHP. The economics of the livestock ADG and waste heat recovery markets, in particular, will most likely depend on sales of excess power to the grid.