Arnold Schwarzenegger
Governor

COMBINED HEAT AND POWER MARKET ASSESSMENT

DRAFT CONSULTANT REPORT

Prepared For:
California Energy Commission
Public Interest Energy Research Program

Prepared By:
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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 (CHP) systems in California from 2009 to 2029. This analysis evaluates the potential contribution of new CHP to the reduction in emissions of greenhouse gases (GHG) as required by the California Global Warming Solutions Act (AB 32) (Assembly Bill 32, Núñez, Chapter 488, Statutes of 2006) in 2006. The analysis characterizes the markets, applications, technologies, and economic competition for CHP over the forecast period. A base case forecast of future CHP 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 (SGIP), providing payments to CHP operators for carbon dioxide savings, and providing a mechanism for the export of CHP power from systems larger than 20 megawatts that are not covered by current legislation to promote CHP 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 (CHP) and the degree to which CHP can reduce potential greenhouse gas (GHG[1]) emissions in support of the California Global Warming Solutions Act of 2006 (AB 32) (Assembly Bill 32, Núñez, Chapter 488, Statutes of 2006). The report also examines how implementing or restoring CHP incentives would affect future CHP market penetration. The analysis covered five task areas:

- Characteristics of existing CHP in California.
- Estimate of technical potential for CHP 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]

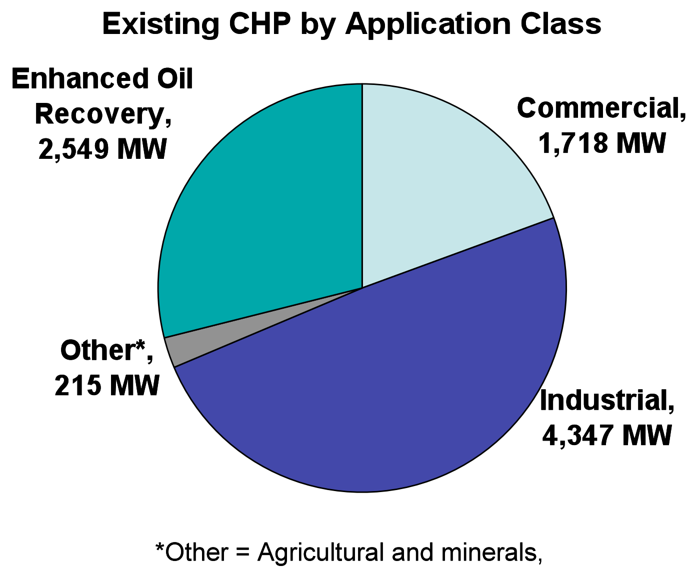
Characteristics of Existing CHP in California

Existing CHP in California was characterized as part of this assessment to aid in both the identification of target markets for CHP and the analysis of remaining technical potential. There are 8,829 megawatts (MW) of active CHP 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 megawatts (MW). **Figure ES-1** shows the breakdown of existing CHP by major market. The largest share of active CHP capacity is located in the industrial sector. The second largest CHP application is the provision of steam and power for enhanced oil recovery in the California heavy oil fields.

More than half of the total CHP capacity is in the industrial sector and is heavily concentrated in five process industries: food processing, refineries, metals processing, pulp and paper, and chemicals. CHP in the commercial and institutional sector is spread through a larger number of individual applications, with the largest being college / universities, healthcare, government facilities, and utility owned CHP systems. While the commercial / institutional share is small compared to the total CHP 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 CHP capacity.

[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 GHG produced from the deployment of combined heat and power.

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



Source: ICF International, Inc. (ICF)

Figure ES-1: Existing CHP Capacity in California by Application Class

Estimate of Technical Potential for CHP 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 CHP in California. The CHP 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 facilities based on the estimated electric and thermal needs of the site.

Table ES-1 summarizes the technical potential for additional CHP in the state by CHP system size and market segment. The estimate includes both additional CHP potential at existing businesses and CHP 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 CHP 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 CHP 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 CHP represents the target market from which *economic* CHP might be developed. These are the applications that are analyzed within the CHP Market Model using appropriate operating characteristics, energy prices, and CHP technology characteristics to determine the economic value of CHP and the resulting market response.

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

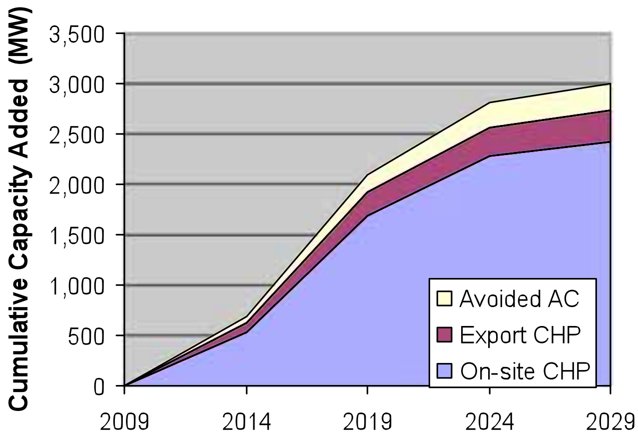
Market	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW	Total
Technical Potential at Existing Industrial and Commercial Facilities (MW)						
High Load Factor	1,152	624	1,522	1,042	245	4,584
Low Load Factor	111	10	5	15	0	141
High Load Factor Cooling	591	269	922	714	563	3,059
Low Load Factor Cooling	2,270	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	255	376
Total	823	283	628	294	397	2,425

Source: ICF

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 CHP market penetration for the Base Case is equal to nearly 3,000 MW. This total CHP capacity is compossed of three components: 2,731 MW for systems that provide power for on-site use, 304 MW for export of power under the AB 1613 program, and 267 MW of avoided electric capacity represented by CHP with thermally activated cooling. The on-site and export components of the total represent actual CHP generating capacity. The avoided electric air conditioning capacity is central station capacity that would have otherwise been needed to supply the air conditioning now provided by the CHP thermal recovery systems.



Source: ICF CHP Market Model

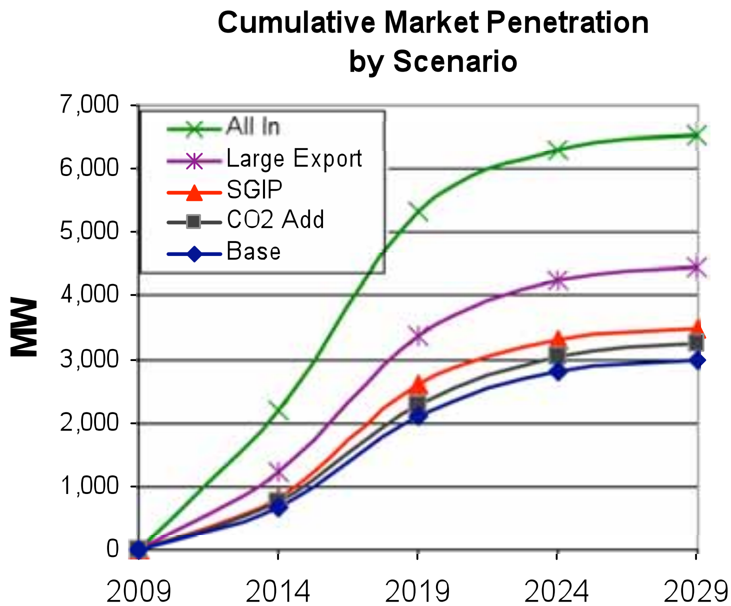
Figure ES-2: Base Case Cumulative Market Penetration by Market Type

Market Analysis Under Alternative Scenarios

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

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

- The CO2 Payments Case assumes that CHP operators receive $50/ton for avoided carbon dioxide emissions compared to the use of purchased power and fuel. The value chosen represents an average of yearly GHG 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 SGIP Case assumes that SGIP incentives are restored to fossil-fueled CHP for a period of 10 years. Bringing back SGIP 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 CHP sizes smaller than 5 MW.
- The AB 1613 CHP 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 CHP-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 uses an aggressive export pricing mechanism unique to this scenario, and includes restoration of the SGIP 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 CHP projects larger than 20 MW.



Source: ICF CHP Market Model

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

Table ES-2 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 kilowatt-hour (kWh) per year by 2029.
- Natural gas for CHP generation will require 188 trillion to 400 trillion Btu / year but will reduce boiler fuel consumption by 50 to 143 trillion Btu / year.
- Average CHP load factor ranges from 75.6 to 82.6 percent, and effective CHP efficiencies range from 62 to 68 percent. 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 / 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
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 AC 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

The market penetration and outputs for the five cases were evaluated with respect to their potential GHG emissions savings and compared to the California Air Resources Board (ARB) Climate Change Scoping Plan target of 4,000 MW of CHP market penetration by 2020. **Table ES-3** shows the annual capacity, energy output, and GHG 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 CHP market assessment scenario that included export access for all CHP system sizes and restoration of the SGIP. 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 CHP 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 CHP efficiencies than were used in the ARB analysis.

The analysis showed that without further changes in CHP regulation or policy (*Base Case*), the CHP 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

Recommendations and Conclusions

The development of policies to stimulate CHP 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 CHP and small CHP. Large CHP represents 87 percent of the existing CHP capacity. Under *Base Case* Assumptions, however, only a very small amount of additional large CHP 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 CHP.

Table ES-4: 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
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

Small CHP will respond to the restoration of SGIP, the addition of CO_2 payments, and the finalization of the AB 1613 feed-in tariff. In addition small CHP 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 CHP. 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 CHP systems sized to the on-site thermal loads within large process industries will often 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 economic price.

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.
- Amelioration of CHP 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 CHP technology cost and performance.
- Reduction of non-bypassable charges that CHP must pay and encouragement of CHP development through appropriate rate treatment.
- Development and implementation of incentives to internalize the social benefits of CHP– energy efficiency, GHG emissions reductions, transmission and distribution system support, peak capacity, and system reliability.

GHG emissions reduction benefits of CHP deployment and use depend not only on the characteristics of CHP 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 CHP operation. These estimates should consider emissions savings differences for 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, further work should be undertaken to evaluate the expected line losses appropriate for different types and sizes of CHP at different times of the year.

CHP thermal usage provides the added GHG emissions savings for CHP compared to the separate purchase of fuel and power. There needs to be an established approach to measure and account for the thermal energy utilization from CHP 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 GHG emissions performance of CHP 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.

[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 (CARB) 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 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.
- CHP Technology Characterization–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:

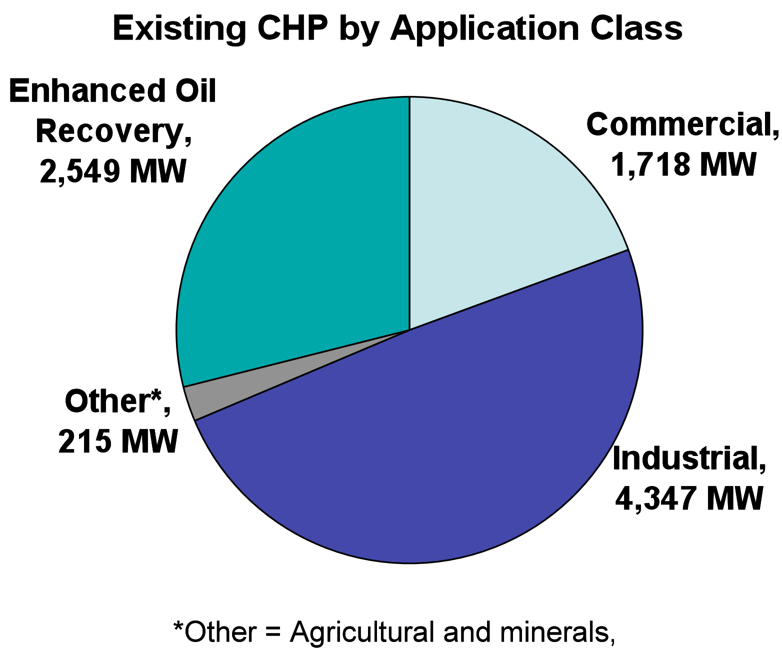
- Analysis of existing CHP in California
- Evaluation of CHP cost and performance by technology and application size
- Determination of current and future gas and electric prices
- Evaluation of CHP technical potential from data on customer characteristics
- Economic analysis of CHP by size and market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

2.1. Existing CHP in California

There are 8,829 MW of active 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.

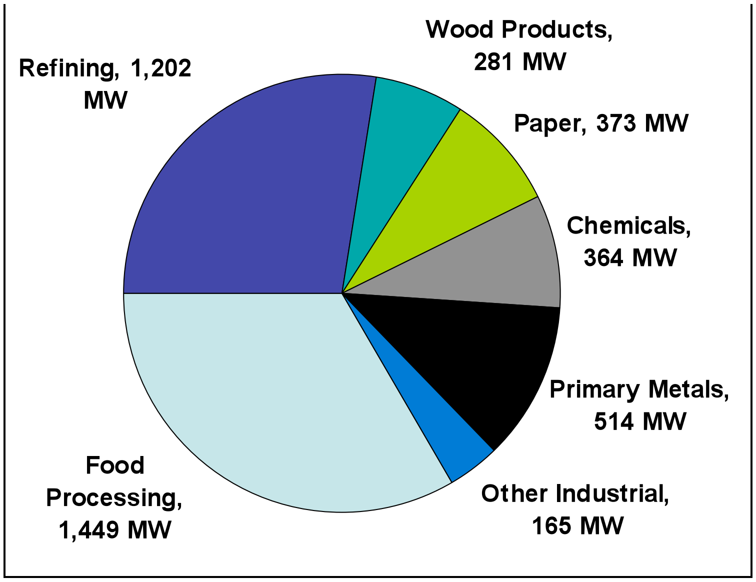
As shown in **Figure 1**, the largest share of active CHP capacity is located in the industrial sector, with the largest single application being the provision of steam in oil fields for enhanced oil recovery (EOR). The figure below shows a breakdown of the existing CHP capacity in California by application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



Source: ICF CHP Installation Database

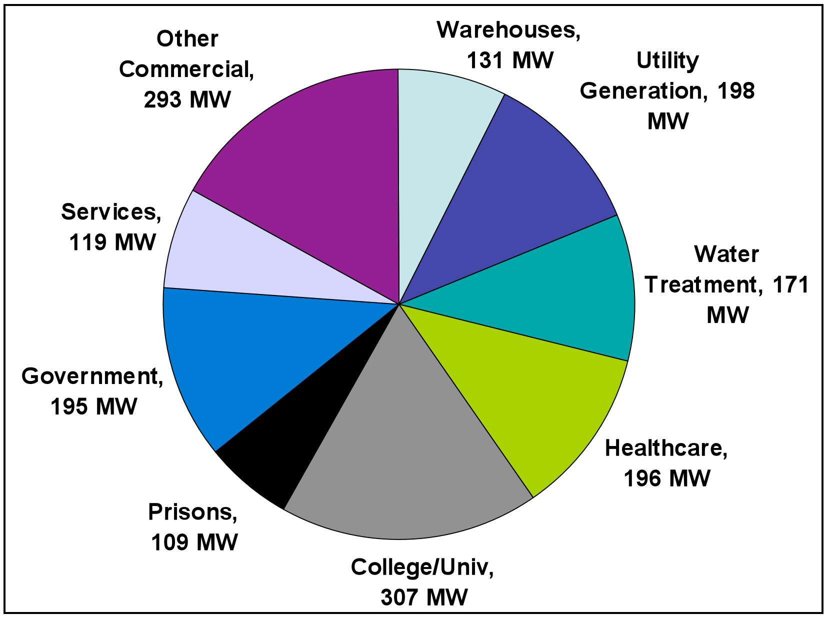
Figure 1: Existing CHP Capacity in California by Application Class

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 applications, with the largest being college/universities, healthcare, government facilities, and utility owned CHP systems. While the commercial/institutional share is small compared to the total CHP capacity in California at 19.5 percent, this market is comparatively well developed compared to the rest of the country; the commercial/institutional sector represents only 11 percent of total CHP capacity on a national basis. **Figure 3** shows the breakdown of CHP in the commercial/institutional sector.



Source: ICF CHP Installation Database

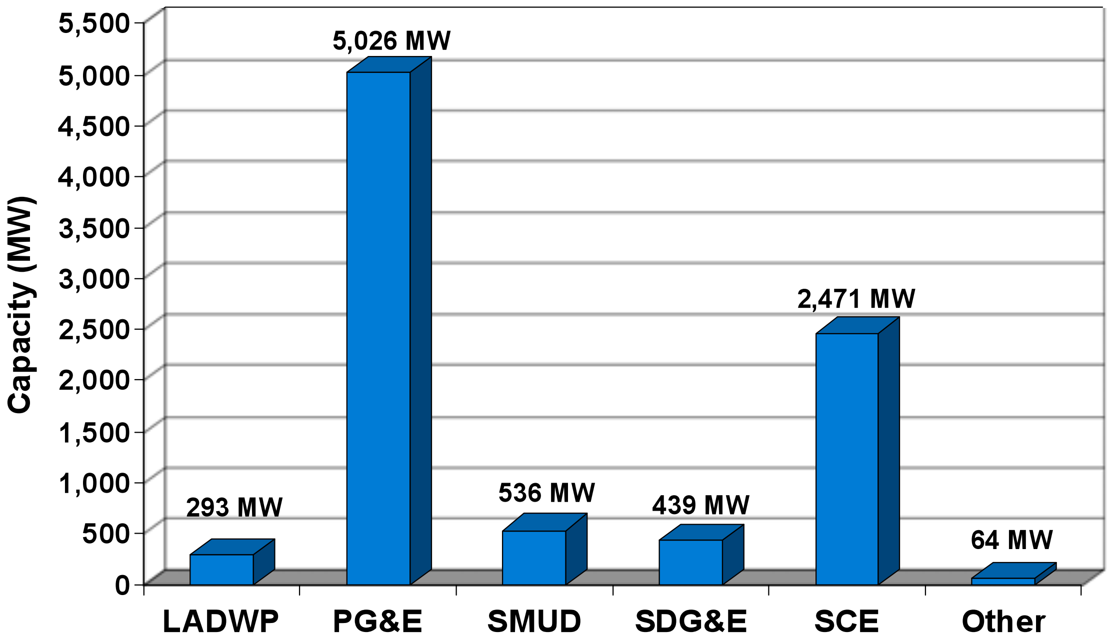
Figure 2: Industrial CHP Capacity in California



Source: ICF CHP Installation Database

Figure 3: Commercial CHP Capacity in California

The geographic location of CHP systems in California is spread out through all major utility territories. Pacific Gas and Electric 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.

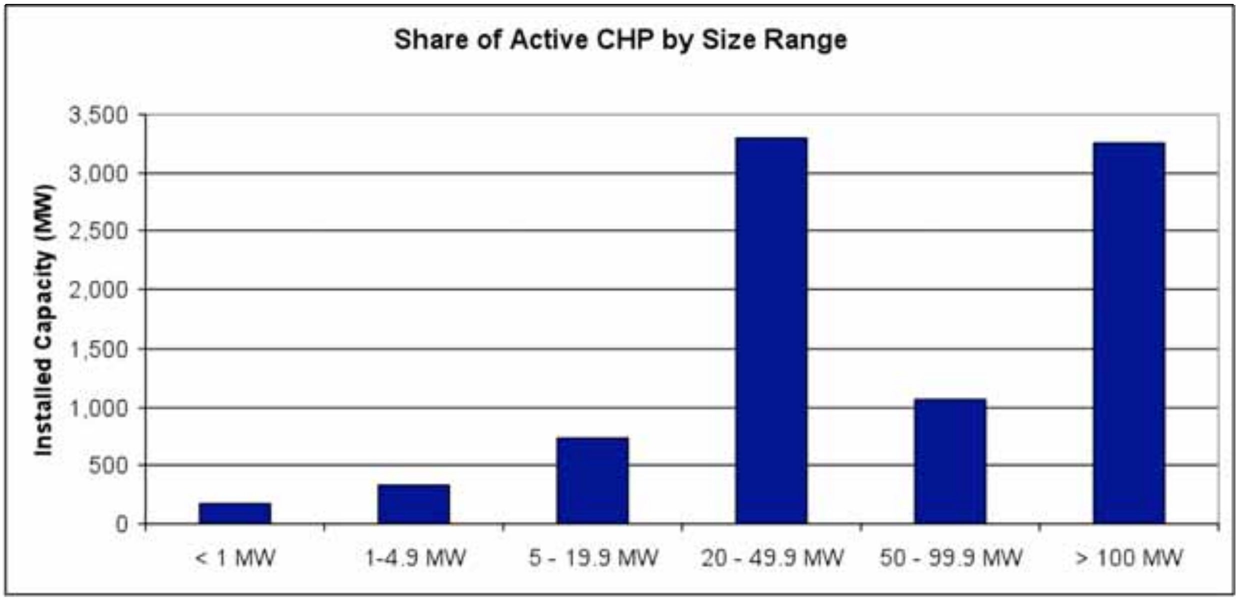


Source: CHP Installation Database

Figure 4: Installed CHP in California by Utility Service Area

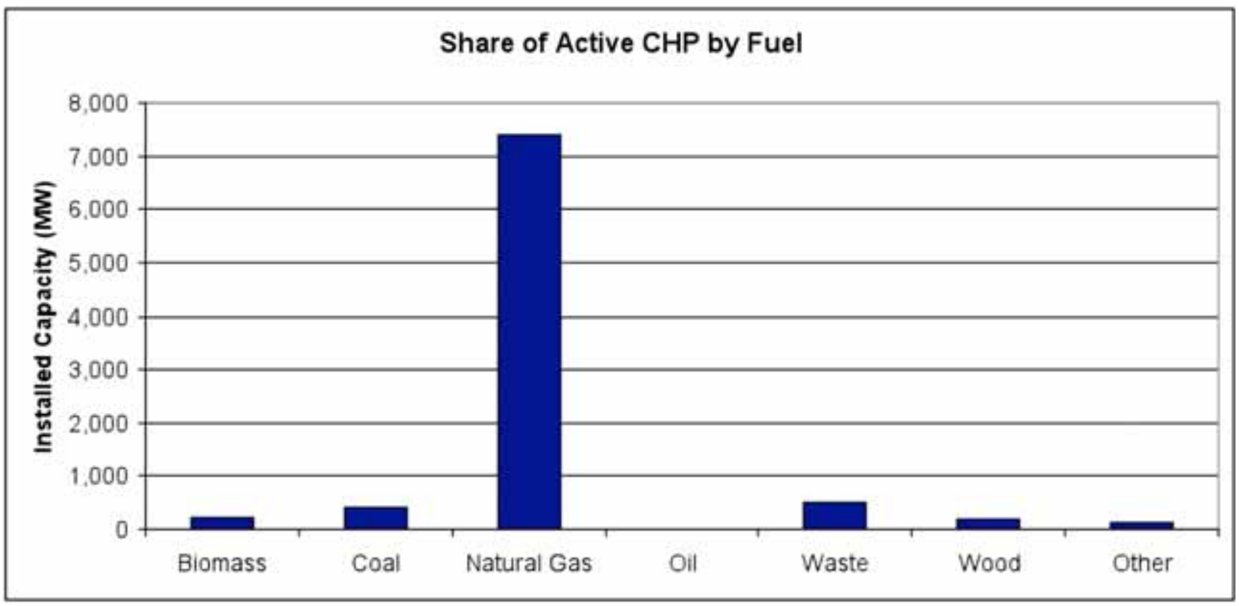
The existing CHP installations can also be characterized in terms of the size of the facility (**Figure 5**), the primary fuel utilized **(Figure 6**), and the type of prime mover **(Figure 7**).

- Large installations make up most of the existing capacity. Systems smaller than 5 MW represent only 5.5 percent of total existing CHP capacity in California. Systems larger than 100 MW represent almost 40 percent 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 comprised of smaller systems.
- By far the most important fuel utilized for CHP is natural gas, which represents 84 percent of the total installed capacity. There are 12 coal-fired CHP plants making up 4.5 percent of capacity, and 5 oil-fired plants making up less than one-tenth of one percent of capacity. Renewable fuel makes up 4.5 percent of the total capacity with the bulk of this capacity in the wood products, paper, and food processing industries and in waste water 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 percent), the reciprocating engine technology represents the greatest number of CHP sites (62 percent). Emerging technologies, such as microturbines and fuel cells, make up a small but growing fraction of systems.



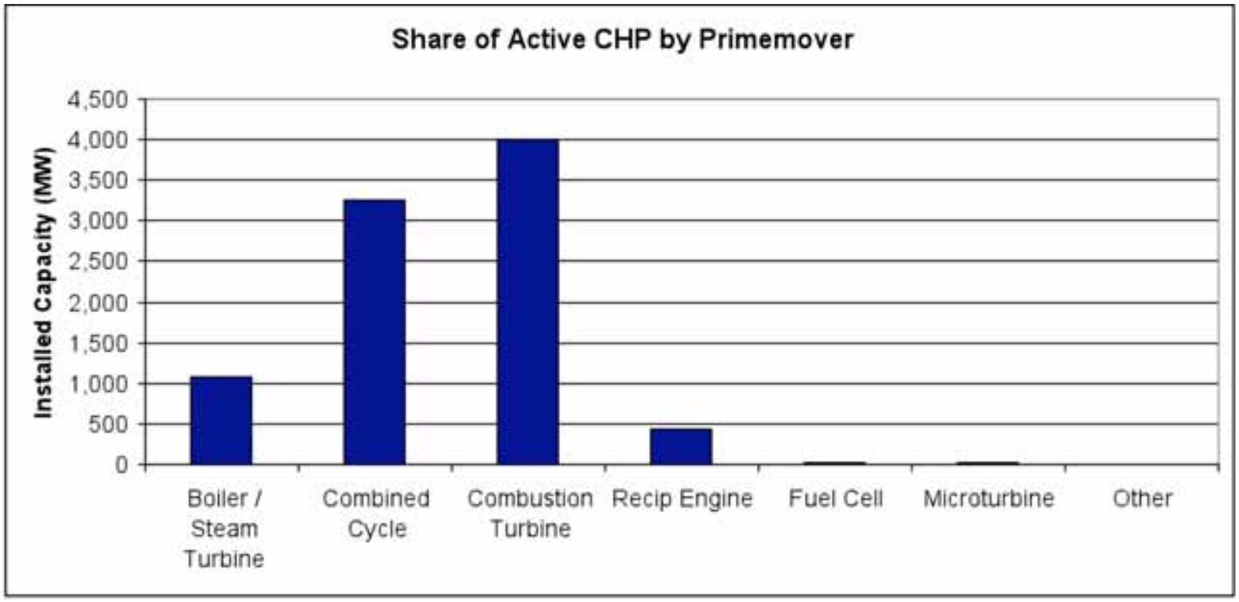
Source: ICF CHP Installation Database

Figure 5: Existing CHP in California by Size Range



Source: ICF CHP Installation Database

Figure 6: Existing CHP in California by Fuel



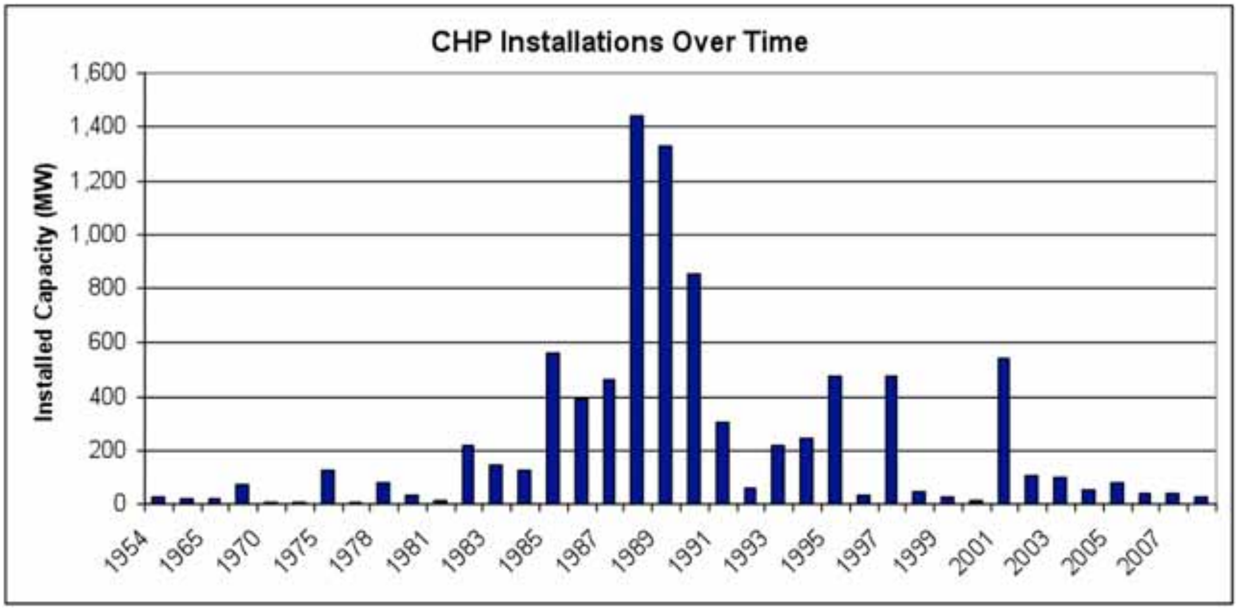
Source: ICF CHP Installation Database

Figure 7: Existing CHP in California by Prime Mover

The installation of CHP systems in California has not been consistent over time. There have been periods of time when more CHP systems have been installed than others, 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 "qualified 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. 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.



Source: ICF CHP Installations Database

Figure 8: Existing CHP Installations in California by Year Installed

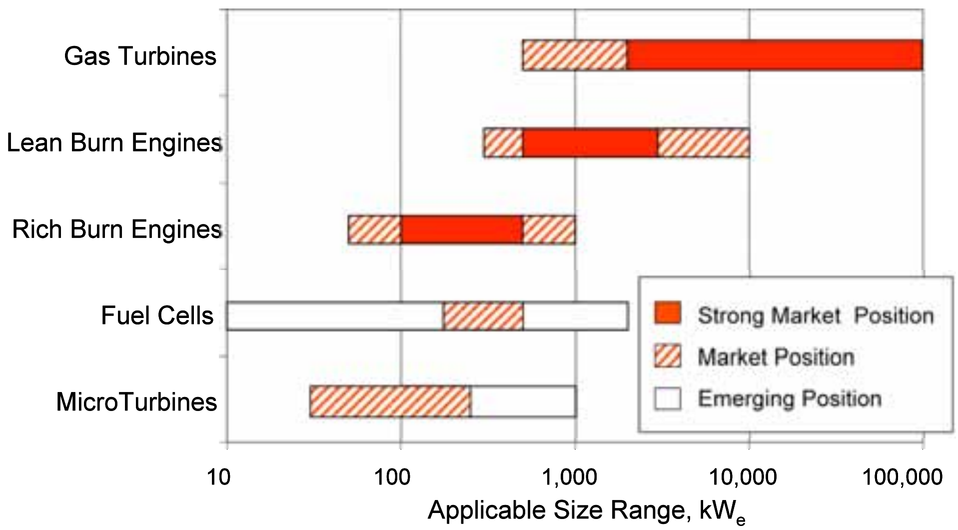
California's Self-Generation Incentive Program (SGIP) has been a recent driver of small CHP system installations. The SGIP provides incentives to support emerging distributed energy resources, which included CHP from 2001 through 2007, on the customer's side of the utility meter. The SGIP program is 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.



Source: Oak Ridge National Laboratory[5]

Figure 9: Technology Size Coverage

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-on 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 and emerging 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 percent-30 percent (HHV) range. Rich burn engines emit high levels of oxides of Nitrogen (NO_x) that are readily treated with passive 3-way catalysts similar to that used in automobiles. With a properly sized and controlled system, these catalysts can achieve emission reductions greater than 99 percent 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 catalyst is required. Advanced SCR systems can remove greater than 95 percent of NO_x emissions allowing lean burn engines to meet the ARB 2007 requirements with the CHP thermal credit.

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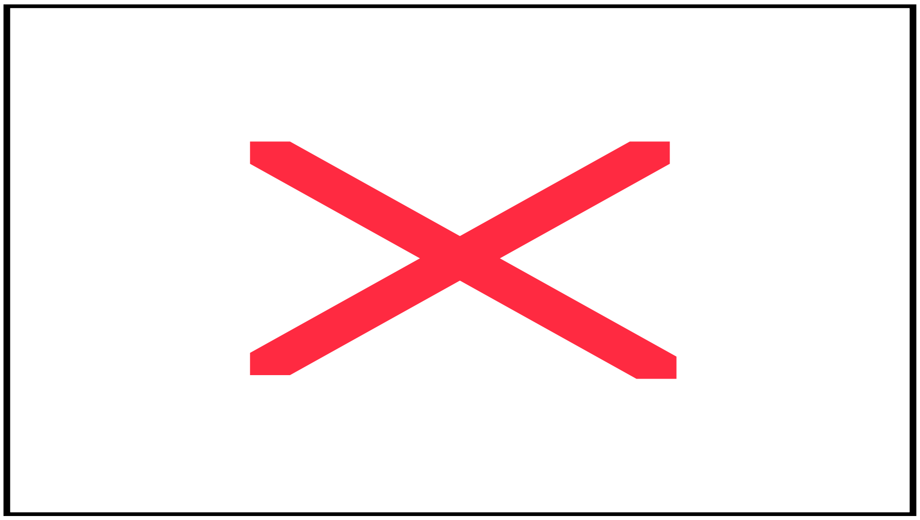
[8] *Gas-Fired Distributed Energy Resource Technology Characterizations,* NREL, November 2003, http://www.osti.gov/bridge.
[9] *Clean Distributed Generation Performance and Cost Analysis,* DE Solutions for ORNL. April 2004.
[10] *Assessment of Emerging Low-Emissions Technologies for Distributed Resource Generators*, EPRI, January 2005.
[11] Engine Manufacturers Association, *Gaseous-Fueled Reciprocating Engines and the Distributed Energy Market,* June 2003

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



Source: DE Solutions

Figure 10: Reciprocating Engine CHP System

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

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

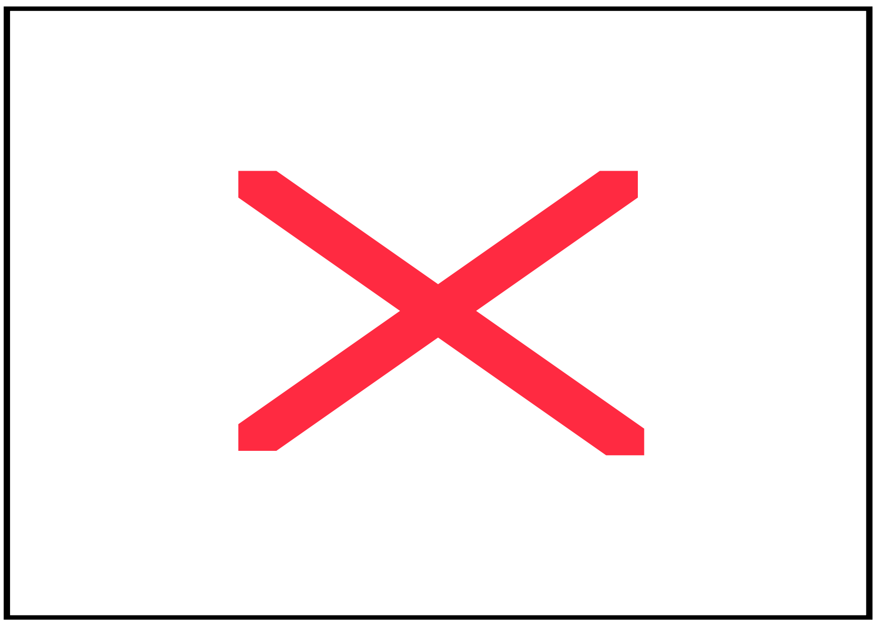
CHP System	Characteristic/Year Available	2009	2014	2019
800 kW-Lean Burn	Installed Costs, $/kW	1,640	1,443	1,246
	CA Installed Costs	1,820	1,602	1,384
	Heat Rate, Btu/kWh	9,760	9,750	9,225
	Electric Efficiency, %	35.0	35.0	37.0
	Thermal Output, Btu/kWh	4299	4300	3800
	Overall Efficiency, %	79.0	79.1	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

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 combined heat and power (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 **Figure 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 vicinity of 900^{o}F, which can be used in a variety of applications including high-temperature steam industrial processes and double-effect absorption cooling.



Source: DE Solutions

Figure 11: Simple-Cycle Gas Turbine

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 pre-heats 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** and **Table 4**.

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

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

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

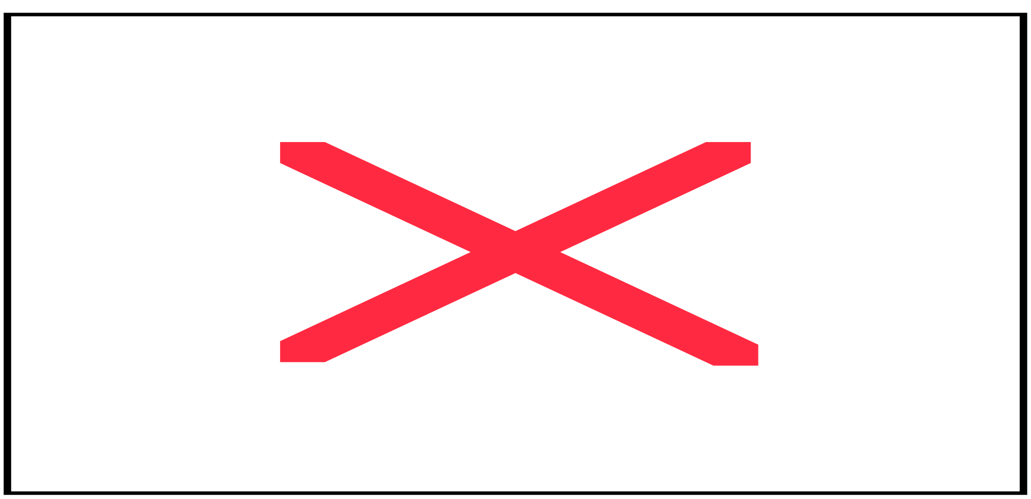
CHP System	Characteristic/Year Available	2009	2014	2019
40 MW GT	Installed Costs, $/kW	972	944	916
	CA Installed Costs	1,079	1,048	1,017
	Heat Rate, Btu/kWh	9,220	8,865	8,595
	Electric Efficiency, %	37.0	38.5	39.7
	Thermal Output, Btu/kWh	3189	3019	2892
	Overall Efficiency, %	71.6	72.5	73.3
	Power to 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

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 percent (HHV) range but are de-rated (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 microturbine s is limited.



Source: NREL

Figure 12: *Microturbine*-Based CHP System

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

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

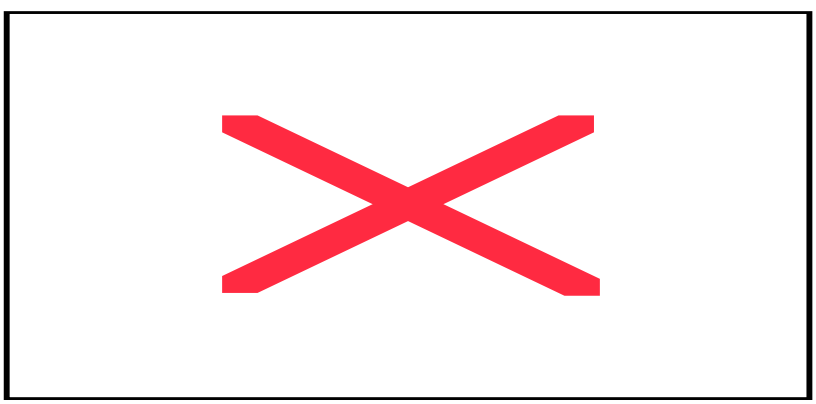
CHP System	Characteristic/Year Available	2009	2014	2019
250 KW-use multiple units	Installed Costs, $/kW	2,684	2,147	1,610
	CA Installed Costs	2,979	2,383	1,788
	Heat Rate, Btu/kWh	12,290	11,750	10,825
	Electric Efficiency, %	27.8	29.0	31.5
	Thermal Output, Btu/kWh	4800	4300	3700
	Overall Efficiency, %	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

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. Source: NREL

Figure 13 illustrates a typical fuel cell process.



Source: NREL

Figure 13: Fuel Cell Electrochemical Process

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 in 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

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

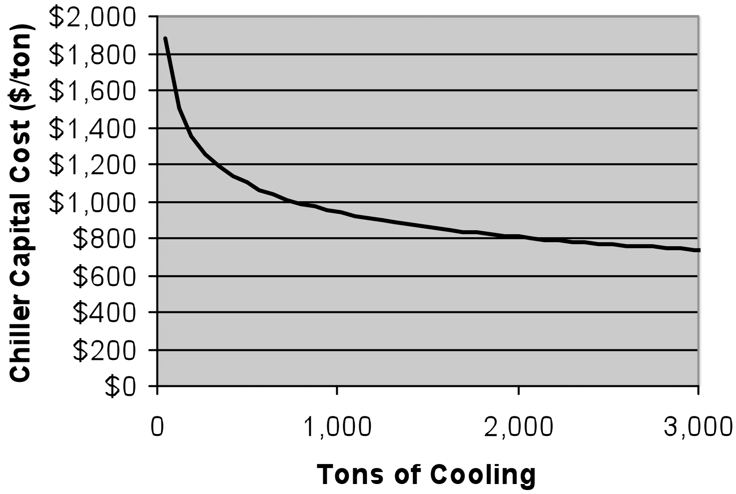
Table 10: Fuel Cell Technology in the 1–5 MW Size Range

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

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**.



Source: ICF

Figure 14: Absorption Chiller Cost Fitting Curve

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

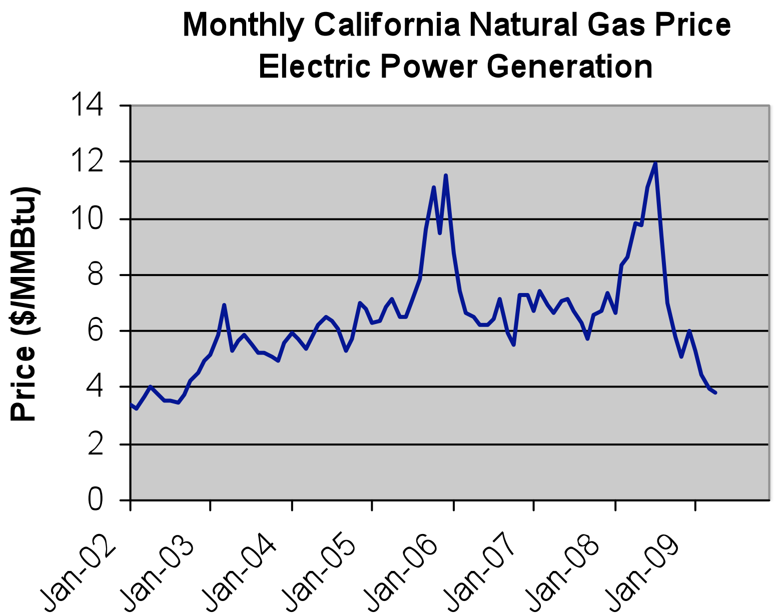
2.3. Natural Gas and Electricity Price Trends

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 of 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.



Source: EIA[12]

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

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 their March 2009 *Reference Case*. The price track chosen from 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).

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[12] Energy Information Administration, Online natural gas monthly price statistics.
[13] Energy Information Administration, Online 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 same 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.

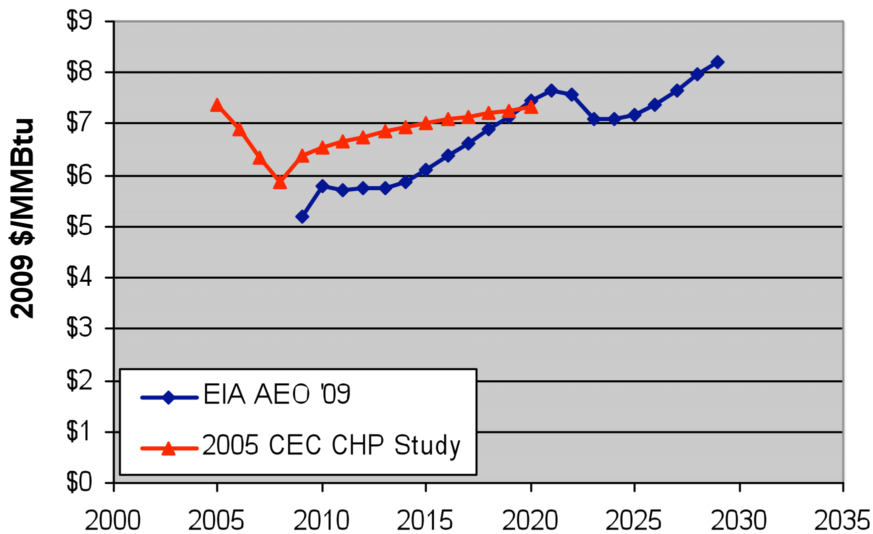


Figure 16: California Natural Gas Price Forecast for Electric Power Generation

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: Edison, PG&E, and SDG&E and the two largest municipal utilities, LADWP and 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 percent 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:

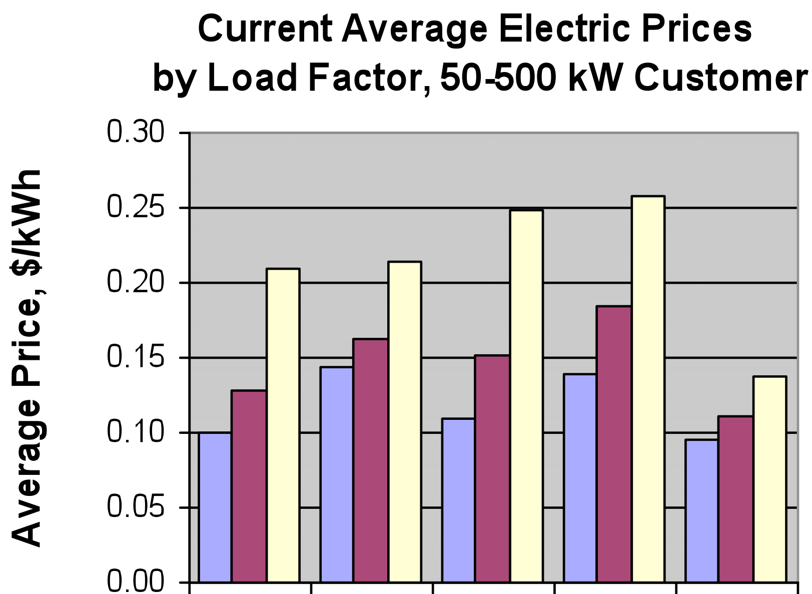
- Analysis of retail rates at three load factors reflecting high load factor (nearly continuous) CHP operation, low load factor CHP operation assuming a peak weighted 4500 hours per year, and an air conditioning load factor based on on-peak operation approximately 2000 hours per year depending on the 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**.

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 percent 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 percent higher than the average high load factor rates depending on the size category.



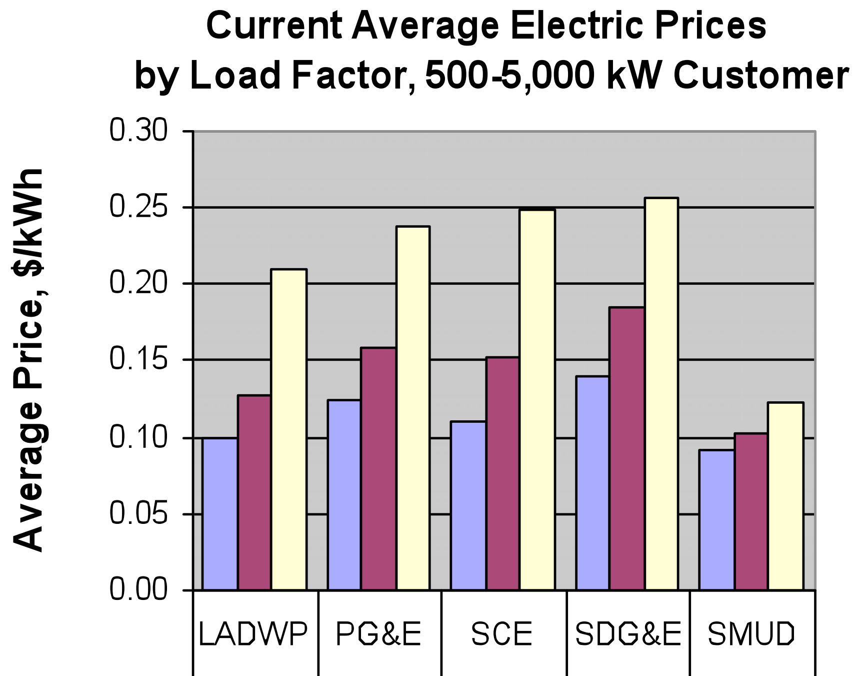
	LADWP	PG&E	SCE	SDG&E	SMUD
High Load Factor	$0.0995	$0.1438	$0.1098	$0.1398	$0.0951
Low Load Factor	$0.1279	$0.1630	$0.1511	$0.1847	$0.1109
Peak AC	$0.2097	$0.2138	$0.2487	$0.2578	$0.1373

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

Source: ICF Analysis of Utility Tariffs

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



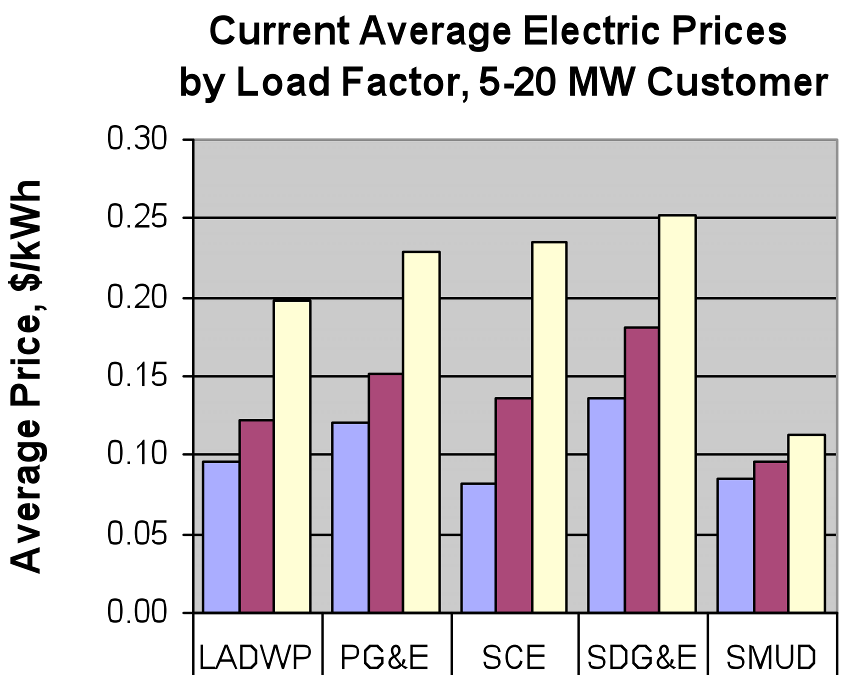
	LADWP	PG&E	SCE	SDG&E	SMUD
High Load Factor	$0.0995	$0.1243	$0.1108	$0.1395	$0.0917
Low Load Factor	$0.1279	$0.1582	$0.1523	$0.1842	$0.1033
Peak AC	$0.2097	$0.2385	$0.2490	$0.2568	$0.1226

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

Source: ICF Analysis of Utility Tariffs

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



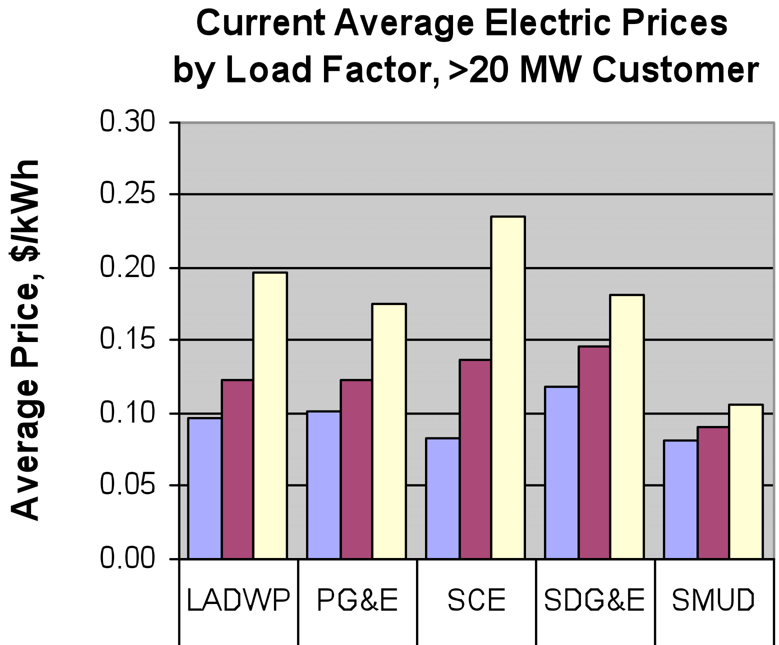
	LADWP	PG&E	SCE	SDG&E	SMUD
High Load Factor	$0.0964	$0.1202	$0.0827	$0.1366	$0.0847
Low Load Factor	$0.1224	$0.1522	$0.1363	$0.1805	$0.0952
Peak AC	$0.1976	$0.2281	$0.2353	$0.2517	$0.1127

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

Source: ICF Analysis of Utility Tariffs

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



	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

Source: ICF Analysis of Utility Tariffs

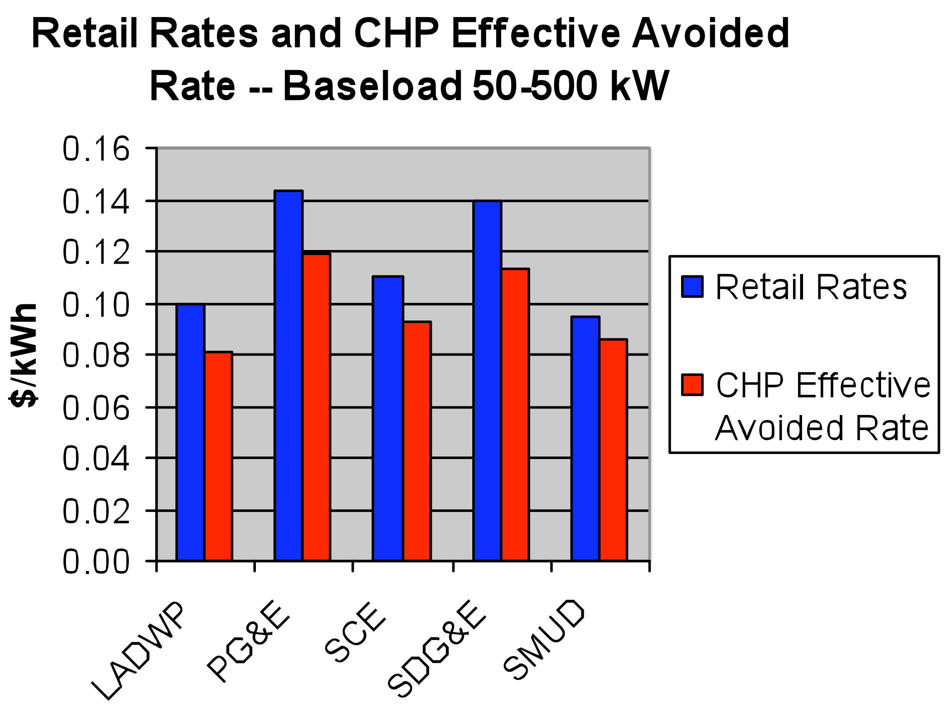
Figure 20: Average Retail Electric Prices by Load Factor, Greater Than 20 MW

Average CHP Savings Rate

Retail electric customers installing CHP within the three IOUs must pay departing load customer responsibility surcharges (CRS), though 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 FERC qualifying facility 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 avoided CHP costs 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 down-time 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.



Source: ICF Analysis of published utility tariffs

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

Table 12: CHP Avoided Electric Costs by Size and Utility

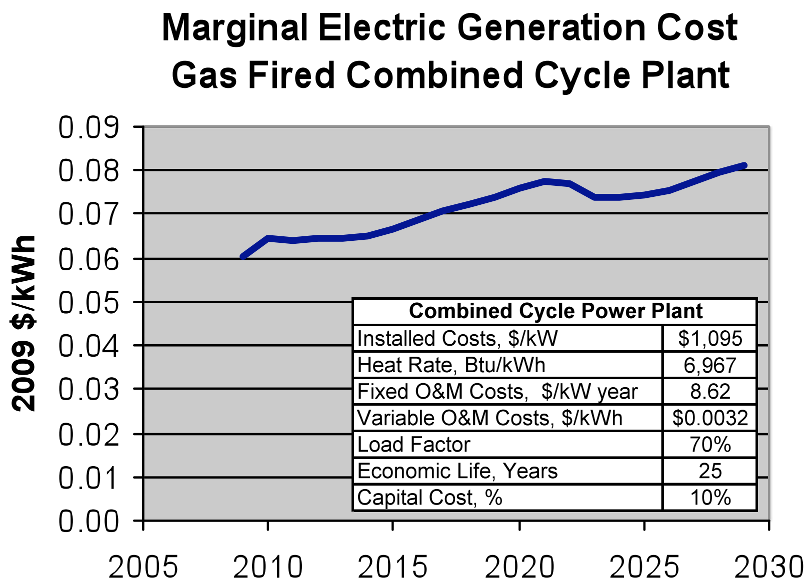
Size	Load Factor	LADWP	PG&E	SCE	SDG&E	SMUD
50–500 kW	High Load Factor	$0.081	$0.119	$0.092	$0.113	$0.086
	Low Load Factor	$0.092	$0.133	$0.120	$0.148	$0.093
500–5,000 kW	High Load Factor	$0.088	$0.095	$0.094	$0.119	$0.083
	Low Load Factor	$0.102	$0.118	$0.122	$0.154	$0.087
5–20 MW	High Load Factor	$0.085	$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

Electric Rate Escalation

The current electric tariffs and CHP avoided costs are escalated into the following four time periods: 2009, 2014, 2019, and 2024. Each of these rates is used to determine the 5-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

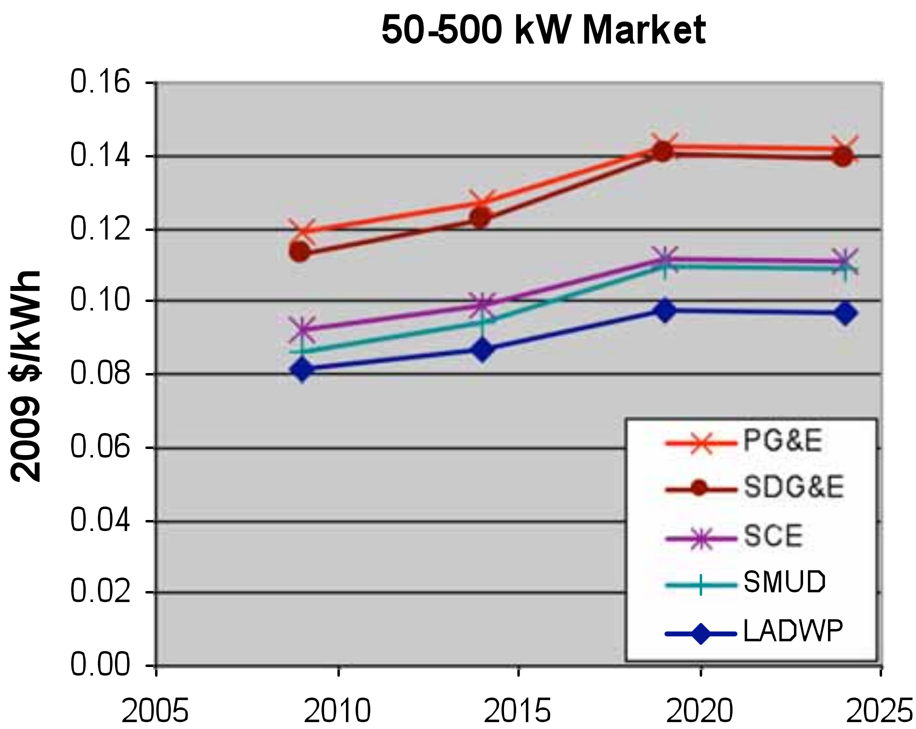


Source of Combined-Cycle Power Plant Assumptions[16]

Figure 22: Real Escalation in Marginal Electric Utility Generation

Prices in the model are taken in 5-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 5-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.



Source: ICF

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

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

Customer CHP Size	Average CHP Avoided Price $/kWh	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

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

Customer CHP Size	Average CHP Avoided Price $/kWh	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

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

Customer CHP Size	Average CHP Avoided Price $/kWh	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

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 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 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 has required 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

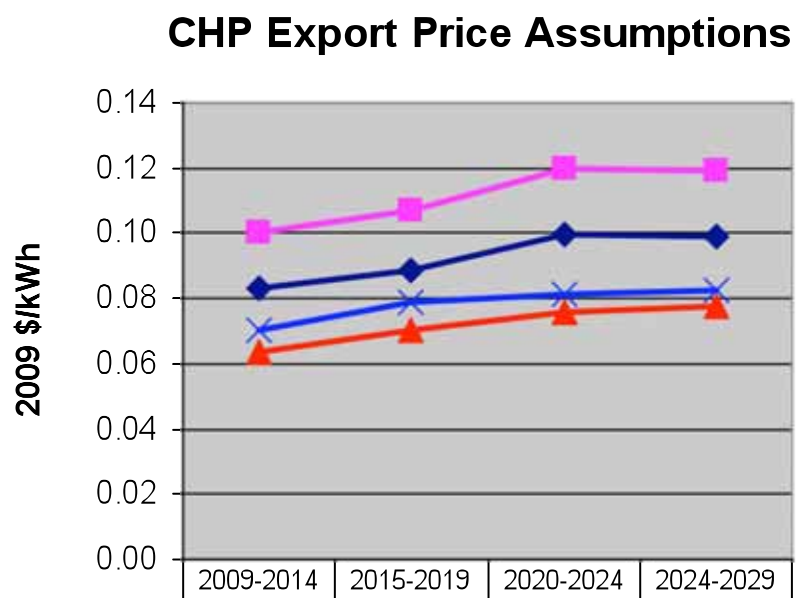
- SMUD has a proposed CHP-FIT for systems up to 5 MW. Export prices are specified for 9 time periods reflecting seasonal peak and off-peak prices. In this and all other cases, the exported power is assumed to occur continuously at a constant rate. The weighted average of the 2009 10-year contract rate 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 percent 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 adders, appropriate for replacing gas-fired generation with 100 percent 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.

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

The 5-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

Source: SMUD, ICF

Figure 24: CHP Export Price Forecasts

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 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, and 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 systems where the electrical output is produced 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. It includes all industrial applications and round-the-clock commercial/institutional operations such colleges, hospitals, hotels, 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, schools, 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 system 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 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 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 assumption that all of the thermal and electric energy is utilized on-site. Within large industrial process facilities, there is typically an excess of steam demand that could support CHP with significant quantities of electricity export to the wholesale power market. The incremental export 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. Regional data sources (D&B, MIPD) 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 a complete list of 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*),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 give a national average electric and thermal demand by application, rather than accounting for regional factors. This is not a critical issue for industrial applications because they tend to be more uniform in their operation nationwide than commercial 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 businesses 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 modify the commercial application electricity and thermal end use levels to be more indicative of a California climate.

There are three fundamental approaches to sizing CHP systems for a given application based on how the thermal energy will be used:

- 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.
- 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.
- Export CHP – Size the CHP system 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 typically an excess of steam demand that could support CHP with significant quantities of exported electricity to the wholesale power system.

The following tables show the applications that were identified in 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
311 - 312	20	Food Processing	Industrial	High
313	22	Textiles	Industrial	High
321	24	Lumber and Wood	Industrial	High
337	25	Furniture	Industrial	High
322	26	Paper	Industrial	High
325	28	Chemicals	Industrial	High
324	29	Petroleum Refining	Industrial	High
326	30	Rubber/Misc Plastics	Industrial	High
331	33	Primary Metals	Industrial	High
332	34	Fabricated Metals	Industrial	High
333	35	Machinery/Computer Equip	Industrial	High
336	37	Transportation Equip.	Industrial	High
335	38	Instruments	Industrial	High
339	39	Misc. Manufacturing	Industrial	High
2213	4941	Water Treatment/Sanitary	Commercial/Institutional	High
92214	9223	Prisons	Commercial/Institutional	High
8123, 8213	7211	Laundries	Commercial/Institutional	Low
71394	7991	Health Clubs	Commercial/Institutional	Low
71391	7992	Golf/Country Clubs	Commercial/Institutional	Low
8111	7542	Carwashes	Commercial/Institutional	Low

Source: ICF

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

2.4.3. California Target CHP Facilities

Various commercial and industrial facility databases were 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. 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 sample of data consisting of facilities in California that have more than 5 employees and are in the target applications specified above. The list 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 replacing the D&B *Selectory* data with MIPD data where there was a match. This process resulted in about 100 of the top industrial plants in the state using detailed electric data from MIPD. The top 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 calculate the total technical potential for CHP in California, each of the potential facilities needs to have a hypothetical CHP system sized to its electrical and thermal loads. The sum of all the individual CHP system potentials 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 the number of employees for sites that did not match with MIPD listings, or the electric demand figures for MIPD sites. To estimate the electric consumption by 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 market assessment of distributed energy facilities, was modified to account for California-specific conditions.

For mining industry NAICS codes, total annual electricity consumption and total number of employees by 6-digit NAICS code were obtained from the 2002 Census of Mining.[18] For manufacturing industry NAICS codes, total annual electricity consumption and total number of employees by 6-digit NAICS code were obtained from the 2002 Census of Manufacturing.[19] Industrial facility NAICS codes were further modified by the percent of energy used for HVAC uses by 3-digit NAICS code from EIA's Manufacturing Energy Consumption Survey (MECS).[20]

For the commercial NAICS codes, a dataset previously purchased by the project team was utilized. The D&B Sales & Marketing Solutions' 2003 MarketPlace database, which has total annual electricity consumption and number of employees by 4-digit SIC code for most of the commercial sector (these 4-digit SIC codes were converted to 3-, 4-, and 6-digit NAICS codes), was used to assign kWh per employee estimates. For NAICS codes for which data was not available, appropriate kWh per employee data was assigned based on information from similar applications. Although the MarketPlace database was the primary data source, some other sources were also used as control totals to make sure the results from MarketPlace 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.21

[18] 2002 US Census of Mining: http://www.census.gov/econ/census02/guide/INDRPT21.HTM
[19] 2002 US Census of Manufacturing: http://www.census.gov/econ/census02/guide/INDRPT31.HTM
[20] EIA MECS: http://www.eia.doe.gov/emeu/mecs/contents.html
[21] AEO 2007 Reference Case: http://www.eia.doe.gov/oiaf/aeo/index.html

These industrial and commercial electricity algorithms were modified from national level estimates to California specific estimates. The modifications took into account California's weather conditions as well as unique industrial and commercial application mix. This adjustment was done through comparing the results of the national level figures with control totals of California industrial and commercial energy use provided by California's Energy Consumption Data Management System (ECDMS).22 Information on known electric and thermal loads for customers in the Sacramento Municipal Utility District (SMUD) was also used to modify the figures to be California specific. This data was provided to the study team for a concurrent market assessment of CHP potential in SMUD territory based on actual customer data. Tables showing the final kWh per employee estimates for California are provided in **Appendix B**.

The average electric load 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 their low electric loads. This assessment utilizes a minimum electric load size range of 50 kW to be included in the technical potential. After being screened for this minimum electric load, only about 36,000 sites remained as potential candidates. **Table 18** shows how the total sites were screened down to the number that entered the 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

Thermal Load Estimation

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 average facility 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, ICF study team used information on thermal loads for the target CHP applications derived from data in DOE's *Commercial Buildings Energy 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 information on the end use of energy in commercial and industrial facilities, so that an average power-to-heat ratio for each target application could be developed.

[22] Energy Consumption Data Management System (ECDMS). http://ecdms.energy.ca.gov/

National level data give a national average power-to-heat ratio by application rather than accounting 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 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)[23], which was used to modify the commercial application power-to-heat ratios to be more indicative of a California climate. CEUS is survey of commercial sector energy use which 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 Pacific Gas & Electric, San Diego Gas and Electric, Southern California Edison, Southern California Gas Company and the Sacramento Municipal Utility District. 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
- Un-refrigerated Warehouses
- Schools
- Colleges
- Healthcare Facilities
- Lodging
- Miscellaneous Commercial Facilities

Industrial Applications—The Major Industrial Plant Database (MIPD)[24] 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 US and then separately for plants in California to pick up any regional differences that may be present. Data on industrial thermal loads was also taken from a combination of the Manufacturing Energy Consumption Survey (MECS)[25] 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

[23] California Commercial End-Use Survey (CEUS). http://www.energy.ca.gov/ceus/
[24] IHS Inc. Major Industrial Plant Database (MIPD). http://energy.ihs.com/Products/Mipd/
[25] Energy Information Administration. Manufacturing Energy Consumption Survey. http://www.eia.doe.gov/emeu/mecs/

estimate the typical industrial thermal loads in California. 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, provided by California's Energy Consumption Data Management System (ECDMS).[26]

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
311 - 312	20	0.533	0.54	0.592
313	22	0.335	0.80	0.844
321	24	0.229	0.50	0.239
337	25	0.801	1.04	1.446
322	26	0.216	0.21	0.275
511	27	0.923	1.07	10.760
325	28	0.400	0.33	0.504
324	29	0.282	0.26	0.258
326	30	0.726	1.09	2.119
327	32	0.244	0.29	4.360
331	33	1.275	1.07	6.633
332	34	0.590	1.06	1.962
333	35	2.268	0.66	3.037
336	37	1.488	0.93	1.482
335	38	4.375	0.62	2.492
339	39	10.329	0.44	0.484

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

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

Commercial Applications—Several sources containing typical commercial electric and thermal loads were evaluated in this assessment. CEUS electric and natural gas usage data by end use was utilized to identify the power-to-heat ratio of target CHP commercial applications. The end use breakdown allowed the thermal loads that could be displaced with CHP to be identified. **Table 20** and **Table 21** show the electric and natural gas intensity data for each commercial application and end-use. 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 assumed to contribute to the thermal portion of the power-to-heat ratio.

Table 20: CEUS Commercial Application Power-to-Heat Ratios

[26] Energy Consumption Data Management System (ECDMS). http://ecdms.energy.ca.gov/

All Commercial	
Electric Loads (kWh/ft2)	13.30
Heating Loads (kWh/ft2)	5.98
P/H ratio	2.22

Small Offices	
Electric Loads (kWh/ft2)	12.65
Heating Loads (kWh/ft2)	3.49
P/H ratio	3.62

Large Offices	
Electric Loads (kWh/ft2)	17.11
Heating Loads (kWh/ft2)	6.78
P/H ratio	2.52

Restaurants	
Electric Loads (kWh/ft2)	39.78
Heating Loads (kWh/ft2)	17.04
P/H ratio	2.33

Retail	
Electric Loads (kWh/ft2)	13.85
Heating Loads (kWh/ft2)	1.35
P/H ratio	10.29

Food Stores	
Electric Loads (kWh/ft2)	40.78
Heating Loads (kWh/ft2)	5.27
P/H ratio	7.73

Refrigerated Warehouses	
Electric Loads (kWh/ft2)	19.97
Heating Loads (kWh/ft2)	1.33
P/H ratio	15.04

Schools	
Electric Loads (kWh/ft2)	7.23
Heating Loads (kWh/ft2)	4.56
P/H ratio	1.59

Colleges	
Electric Loads (kWh/ft2)	11.38
Heating Loads (kWh/ft2)	9.17
P/H ratio	1.24

Health	
Electric Loads (kWh/ft2)	18.82
Heating Loads (kWh/ft2)	21.06
P/H ratio	0.89

Lodging	
Electric Loads (kWh/ft2)	11.67
Heating Loads (kWh/ft2)	11.14
P/H ratio	1.05

Miscellaneous	
Electric Loads (kWh/ft2)	9.61
Heating Loads (kWh/ft2)	6.36
P/H ratio	1.51

Source: California Commercial End-use Survey

Overall, the CEUS data helped in determining the final commercial power-to-heat ratios that were used in this market assessment. **Table 21** shows how the CEUS figures compared to EIA's Commercial Building Energy Consumption Survey (CBECS)[27], and other sources of commercial electric and thermal data.

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

Table 21: Commercial Power-to-Heat Ratio Estimates

	CBECS P/H Ratio	CEC CEUS P/H Ratio	Other Sources P/H Ratio
Principal Building Activity			
Education	0.81	1.59	0.67
Food Sales	3.90	7.73	5.93
Food Service	0.76	2.33	2.47
Health Care	0.80	0.89	0.9
Lodging	0.75	1.05	0.82
Retail	1.78	10.29	1.33
Office	1.64	2.52	2.3
Public Assembly	0.80	na	0.72
Public Order and Safety	0.80	na	0.89
Religious Worship	0.57	na	0.52
Service	1.09	2.22	na
Warehouse and Storage	1.29	4.49	1.45
Other	0.96	1.51	1.18
Colleges	na	1.24	na

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 are 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:

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

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

CHP System Size = Site Average Electric Demand x Thermal Factor

A thermal factor of one would result in the CHP system being the same size as 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 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

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

Source: ICF

Once the final power-to-heat ratios for each commercial application were determined, they were applied to the customer electric loads to estimate an appropriately sized CHP system at each site. However, unlike the industrial thermal load estimation, a commercial CHP system cannot be assumed to achieve 100 percent thermal utilization. Similar to the process of narrowing in on the thermal load values that most closely matched industrial power-to-heat ratios with known total sector values, various commercial thermal utilization combinations were tested to see which thermal utilization values produced the most accurate results to California-specific control totals. The following thermal utilizations were analyzed:

Heating Applications:

- 100 percent hot water, 100 percent space heating
- 80 percent hot water, 80 percent space heating
- 100 percent hot water, 60 percent space heating
- 60 percent hot water, 50 percent space heating

Cooling Applications:

- 50 percent cooling
- 60 percent cooling

The commercial technical potential results vary notably depending on which thermal utilization combination is used. After comparing the results to known control totals, it was determined that 80 percent hot water and space heating load, and 60 percent of cooling load were the most appropriate thermal utilization figures.

After a hypothetical CHP system was sized 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 has a higher amount of technical potential than is currently installed, the difference was considered to be the remaining potential at the site.

The estimation of technical potential for additional CHP for enhanced oil recovery comes from an analysis of the potential at 10 existing oil fields and the degree of market saturation that already exists for CHP. **Table 25** shows the estimation for additional CHP potential for enhanced oil recovery.

Table 25: Technical Potential for Additional CHP From Existing Oil Fields

Field	Projects	Power Capacity MW	Natural Gas Usage (MMcfd)	Cogenerated Steam Injected (MBS/D)	Total Steam Injected	CHP %	Remaining Potential MW
Kern River	10	812	220	371	371	100%	0
Midway-Sunset	10	415	121	281	478	59%	291
Kern Front	4	189	44	25	25	100%	0
Placentia	2	142	49	20	20	100%	0
San Ardo	3	82	24	53	53	100%	0
South Belridge	2	75	22	60	291	21%	289
Coalinga	5	59	22	65	87	75%	20
Mt. Poso	1	50	(coal)	3	11	27%	133
Cymric	4	27	33	34	76	45%	33
Lost Hills	1	10	4	8	37	22%	36
Total 10 Fields	**42**	**1861**	**539**	**920**	**1449**	**63%**	**1,070**

Source: EPRI[28]

2.4.5. Technical Potential Results

The CHP technical market potential was estimated for both 2009 and 2030. This section provides the CHP technical potential estimates by application and size range for the whole state and for each utility. The estimates are divided into 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. 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 technical market potential for the traditional CHP market equals 16,071 MW in 2009 for existing facilities with 2,346 MW from expected new facilities during the forecast period, for a total of more than 18,000 MW in 2030. **Table 26**, **Table 27**, **Table 28**, **Table 29**, and **Table 30** show the current and future technical potential figures broken down by application and utility territory.

Technical Potential—2009

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, due to the fact that 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.

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

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

SICs	Application	50-500 kW (MW)	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (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

Commercial facility CHP potential is heavily concentrated in the size ranges below 5 MW, where almost 80 percent 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 27: On-Site CHP Technical Potential at Existing Commercial Facilities in 2009

SICs	Application	50-500 kW MW	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (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

The export market comes primarily from the top one hundred 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. There is a total technical CHP export potential of 4,544 MW.

Table 28: Export CHP Technical Potential at Existing Facilities in 2009

SICs	Application	50-500 kW MW	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total MW
13	Enhanced Oil Recovery	0	0	0	0	1070	1070
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	1093
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**	**3530**	**4544**

Source: ICF

The total technical potential for CHP in California for 2009 is shown in **Table 29**. It indicates that there is more remaining potential in commercial facilities than in industrial facilities which is a switch 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 onsite needs, leaving the remaining large size system potential in the export market.

Table 29: Total CHP Technical Potential in 2009 by Market Sector

Market Type	50-500 kW MW	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total MW
Industrial Onsite	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

The utility with the largest amount of CHP technical potential is Pacific Gas and Electric (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 30: Total CHP Technical Potential 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

Technical Potential –Growth 2009-2029

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 facilities and growth 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 capacity additions at existing facilities. In cases where an economic sector is declining, it was assumed that no new facilities would be added to the technical potential for CHP.

Table 31: Industrial Application Growth Projections

SICs	Application	2008-2029 Growth
20	Food	33.80%
22	Textiles	0.00%
24	Lumber and Wood	35.51%
25	Furniture	6.29%
26	Paper	7.91%
28	Chemicals	0.00%
29	Petroleum Refining	0.00%
30	Rubber/Misc Plastics	0.00%
33	Primary Metals	0.00%
34	Fabricated Metals	0.00%
35	Machinery/Computer Equip	11.90%
37	Transportation Equip.	11.36%
38	Instruments	12.52%
39	Misc. Manufacturing	33.97%

Source: EIA 2009 Annual Energy Outlook, Stimulus Case

Table 32: Commercial Application Growth Projections

SICs	Application	2008-2029 Growth
43	Post Offices	13.65%
4581	Airport Facilities	25.67%
5812	Restaurants	15.20%
6512	Comm. Office Buildings	27.30%
6513	Apartments	8.62%
7542	Carwashes	27.30%
7832	Movie Theaters	32.46%
8412	Museums	15.32%
4222, 5142	Warehouses	14.40%
4941, 4952	Water Treatment/Sanitary	27.30%
52,53,56,57	Big Box Retail	32.46%
5411 - 5461, 5499	Food Sales	27.96%
7011, 7041	Hotels	25.67%
7211, 7213, 7218	Laundries	25.67%
7991, 00, 01	Health Clubs	27.30%
7992, 7997	Golf/Country Clubs	25.67%
8051, 8052, 8059	Nursing Homes	35.81%
8062, 8063, 8069	Hospitals	35.81%
8211, 8243, 8249, 8299	Schools	19.82%
8221, 8222	Colleges/Universities	19.82%
9223, 9211, 9224	Prisons	25.67%

Source: EIA 2009 Annual Energy Outlook, Stimulus Case

Table 34 and **Table 35** show the additional CHP technical potential due to growth in existing facilities in California. Due to recent economic factors, the growth rates for several industries are not as strong as they once were, leading to a lower amount of new technical potential additions in the forecast period.

Table 33: Total CHP Technical Potential Additions Between 2009 and 2029 by Market Sector

Market Type	50-500 kW MW	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (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

Table 34: CHP Technical Potential Additions Between 2009 and 2029 by Utility Territory

Utility	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW	Total
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

The total technical potential for CHP in 2029 is the combination of the 2009 technical potential and the potential in the facility additions between 2009 and 2029. The tables below summarize the total technical potential for CHP in 2029.

Table 35: Total Industrial CHP Technical Potential in 2029

SICs	Application	50-500 kW (MW)	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (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

Table 36: Total Commercial CHP Technical Potential in 2029

SICs	Application	50-500 kW MW	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (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**

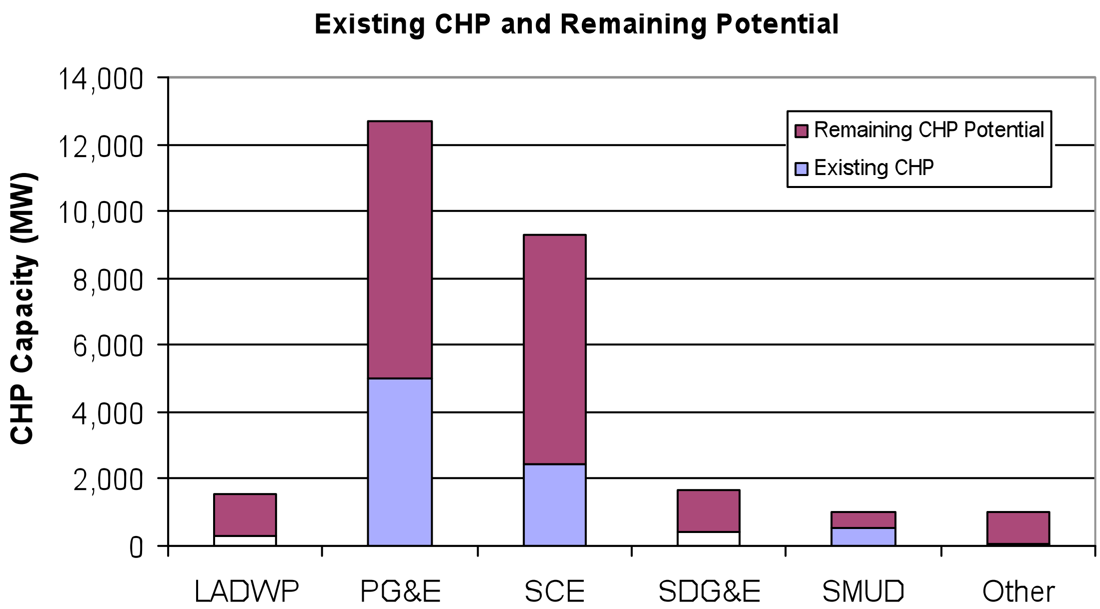
Source: ICF

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
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

California contains significant technical potential for growth in CHP installations. Considering all markets and both existing and new facilities, there is a total technical market potential of over 18,000 MW. The most significant regions for growth are in the PG&E and SCE service territories; however the other utilities in California also have significant room for growth as demonstrated in **Figure 25**.



Source: ICF

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

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

All of these factors will be accounted for in the CHP market model to estimate the 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

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

The seven utility regions consist of the three major investor owned utilities: Southern California Edison (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas and Electric Company (SDG&E). Two large municipal utilities are also represented: Los Angeles Division of Water and Power, (LADWP) and Sacramento Municipal Utility District (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 5-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 comprised 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 5 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
In Existing 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 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

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 percent and are gradually reduced to nothing 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

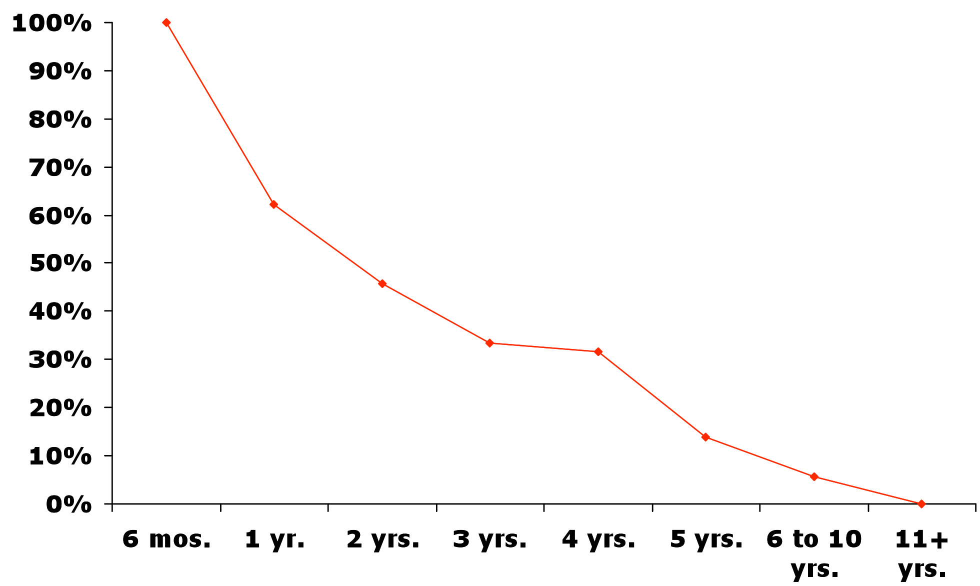
The economic competitiveness calculation within the ICF CHP Market Model is a simple payback calculation. The annual cost of operating the CHP system is compared to the avoided thermal and electric energy cost savings, allowing the number of years it would take for this annual savings to repay the initial 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 which 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. As can be seen from the figure, more than 30 percent 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 2 years. This type of payback translates into a project with an ROI of between 49–100 percent.



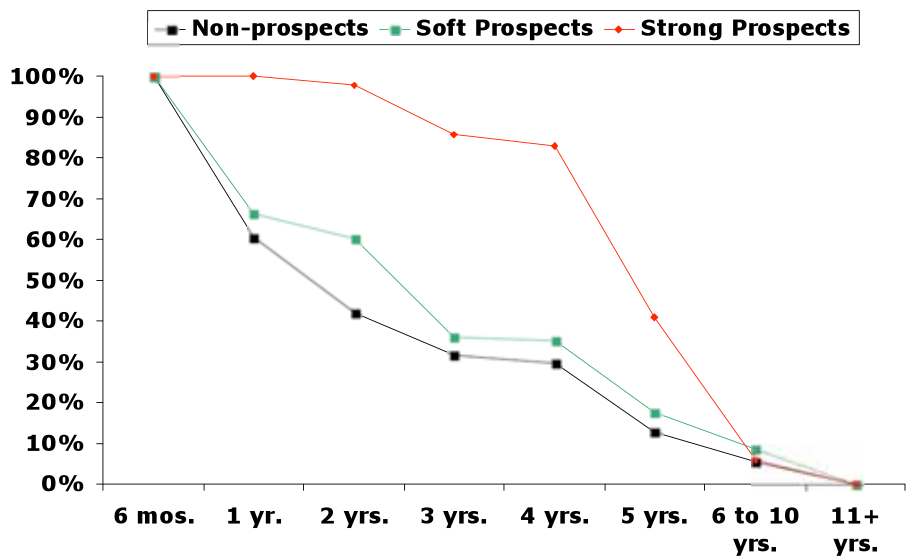
Source: *Primen's 2003 Distributed Energy Market Survey*

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 4 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, but they are used in the model to reflect actual expected customer behavior in the absence of any change in perceptions regarding the risk of investing in CHP.

However, in public comments made following a workshop presentation of preliminary results from this study[29], the study team decided that large potential CHP exporters were a great deal more sophisticated than the average facility operator and also were 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 percent likely to go forward with a project in the next two years, were willing to accept longer paybacks – up to a point. Almost 90 percent of strong prospects would consider a payback of 4 years, but acceptance begins to drop rapidly once paybacks reach 5 years. **Figure 27** shows the market acceptance curve for strong prospects that was used to define the market acceptance for the large export market.



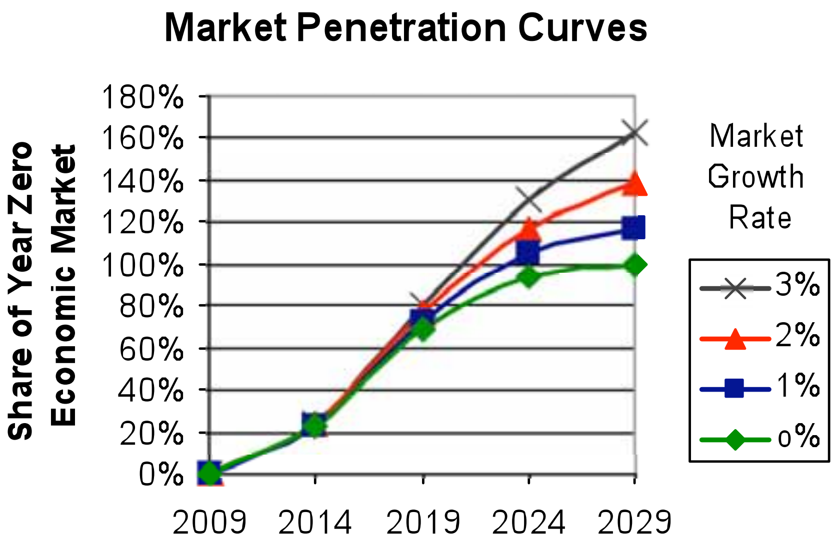
Source: *Primen's 2003 Distributed Energy Market Survey*

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.

[29] Beth Vaughan and Evelyn Kahl, Comments of the Energy Producers and users Coalition, the Cogeneration Association of California, and the California Cogeneration Council, Docket 09-IEP-1H, August 6, 2009.

The market acceptance curve defines the market that will ultimately install CHP in their facilities, but all of this economic potential does not penetrate the market at once. 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 5-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 percent 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.



Source: ICF

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

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 Self Generation Incentive Program (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 all described in the *Project Approach*.

In addition all scenarios include the 10 percent federal tax credit for qualifying CHP facilities up to 50 MW in size. Fuel cell systems receive a 30 percent 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.

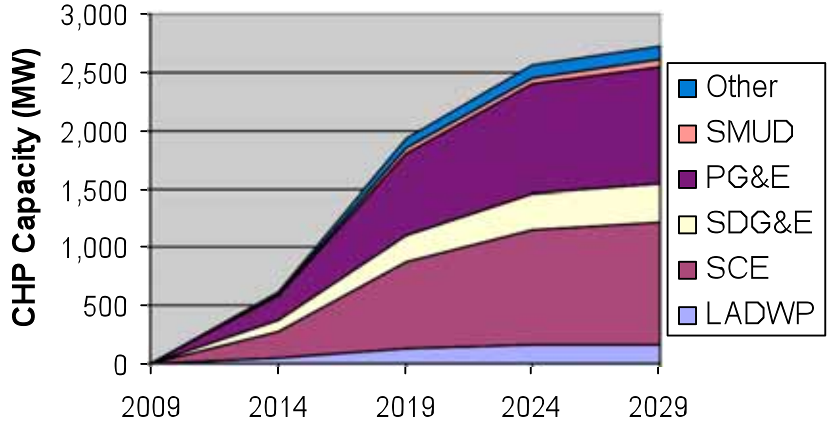
3.1.1. Base Case Input Assumptions

Assumptions specific to the *Base Case* consist of the following:

- The Existing SGIP incentives are assumed to 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.

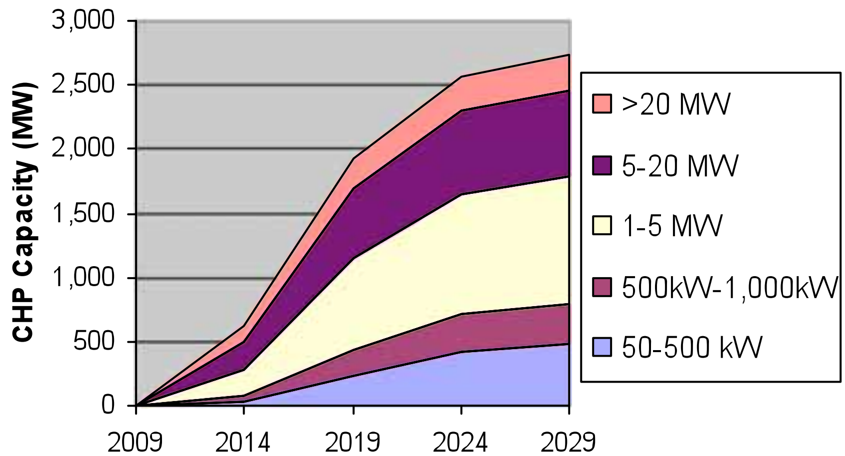
3.1.2. Base Case Results

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 percent 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 percent of the total market penetration. The 5 to 20 MW size category makes up 25 percent 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 percent of the new market penetration expected over the next 20 years.



Source: ICF CHP Market Model

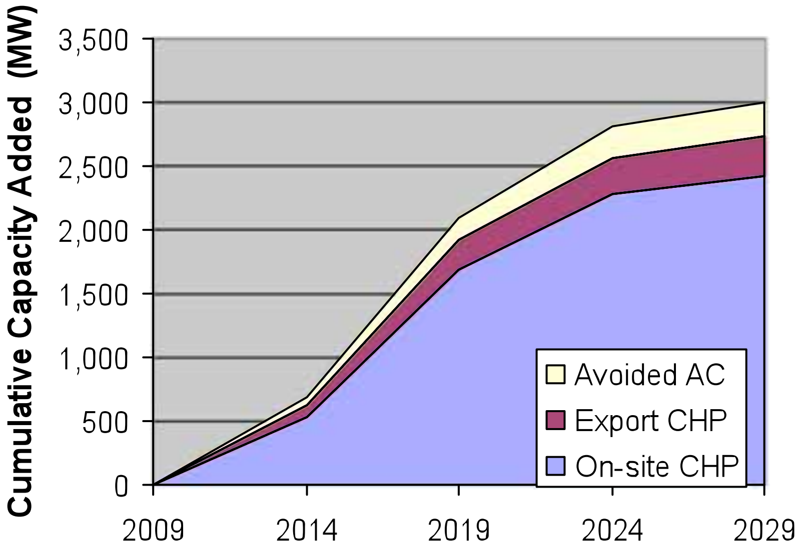
Figure 29: Base Case Cumulative New CHP Market Penetration by Utility



Source: ICF CHP Market Model

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

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.

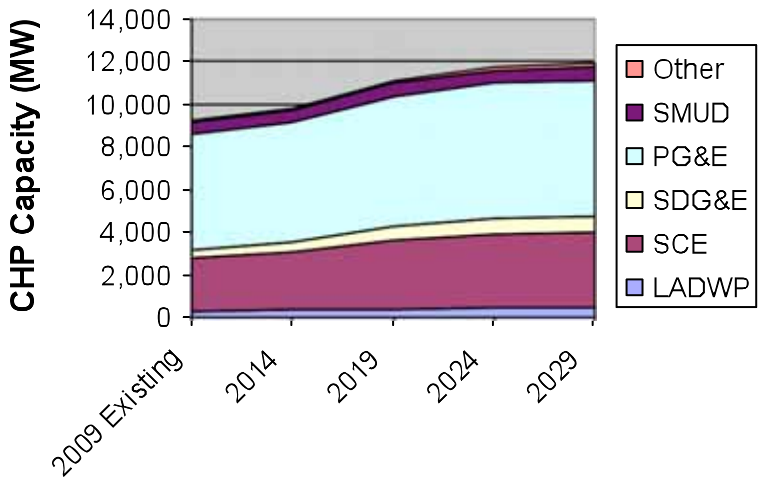


Source: ICF CHP Market Model

Figure 31: Base Case Cumulative Market Penetration by Market Type

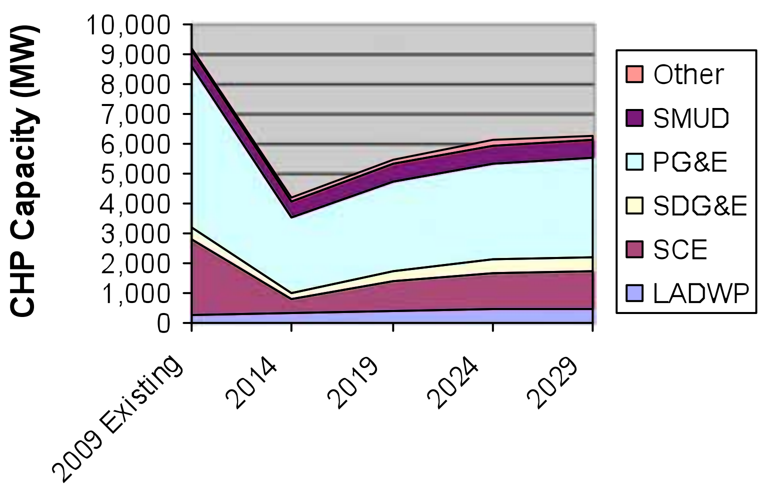
The focus of this analysis and of the ICF CHP Market Model is on new CHP market penetration as shown in the previous figures. To put the new CHP market penetration into perspective, **Figure 32** shows the same market penetration as was shown in **Figure 29**, but shows this penetration on top of the 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 percent of CHP capacity in 20 years and new systems that enter the market during this period only 25 percent.

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.



Source: ICF CHP Market Model, ICF CHP Installation Database

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.

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 percent 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. Therefore, an average value of $50/ton of CO_2 emissions reduction is provided for all CHP electric output and also for avoided electricity generation due to CHP supplied air conditioning as well.

The 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, 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 tacks do not include any CO_2 adjustment. This is not an issue when adding the CO_2 payments to the base case because no large export market is assumed to exist.

Restore SGIP Case

Restoration of the Self Generation Incentive Program (SGIP) is under consideration in the California legislature (SB 1412 Kehoe). If this bill is enacted, the CPUC would be required to re-implement SGIP using their discretion about program details. For this analysis we assumed that all 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 up-front 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

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

applied to the first MW for qualifying systems under 5 MW of capacity. Currently, there is an extension of this payment to provide partial payments for the next two MW of capacity–50 percent incentive for the second MW of capacity, and 25 percent 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 when they are finalized, will only apply to systems 20 MW or less. In the *Base Case*, no mechanism for exporting power from larger facilities (greater than 20 MW) was 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 assumptions defined by the Energy Commission Staff Report.[31]

The large export market were also assumed to be strong prospects, that is their acceptance curve for various project paybacks is much stronger than the state average for paybacks that are 5 years or less.

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 was shown in **Figure 27** (Strong Prospects).

These assumptions, and consequently the results, are different from the assumptions that were used in preliminary analysis that was presented at the Integrated Energy Policy Report (IEPR) public workshop on CHP.[32] The Energy Commission assumptions on the cost and performance of a conventional combined cycle power plant were somewhat different than the original assumptions used, though overall, the resulting large export contract prices are only slightly higher. The biggest difference is the use of the *strong prospects* market acceptance curve. Several comments from representatives of this market indicated that market acceptance of 5-year and less paybacks would be much stronger than the average market acceptance curve used for the other markets.

Strong Stimulus Large Export Case

A second contract price track for large export CHP projects was also evaluated as shown in **Figure 24** (aggressive contract price) and described in the accompanying text as being based on 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 was used in the *"All-In" Case* in place of the basic expanded export case assumptions just described.

"All In" Incentives Case

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

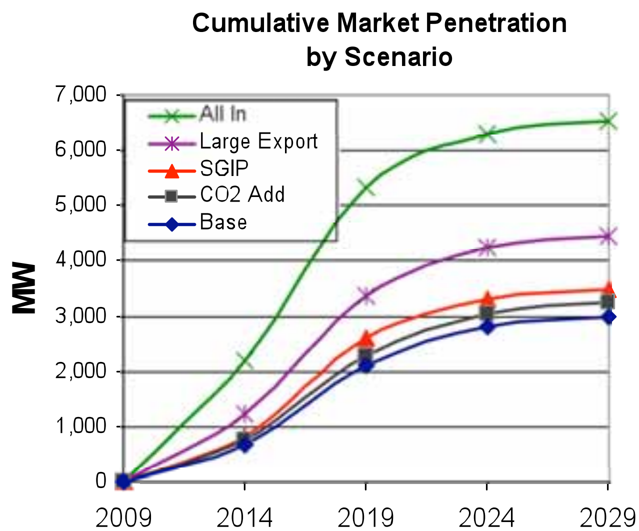
[32] Ken Darrow, et al., "CHP Market Assessment," *Integrated Energy Policy Report Combined Heat and Power Workshop*, ICF International, Inc., July 23, 2009.

The *“All-In” Case* represents a combination of restoration of SGIP, addition of CO_2 emissions reduction payments of $50/ton, and encouragement of large export projects with the aggressive contract pricing mechanism and accompanying CO_2 payments.

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 measures plus a more aggressive large export contract price, the market increases by 3,521 MW–79 percent of this increase is in the export market.



Source: ICF CHP Market Model

Figure 34: Incentive Cases Cumulative Market Penetration Results

Table 42: Incentive Cases 2029 Cumulative Market Penetration by Market Type

CHP 2029 Capacity MW	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

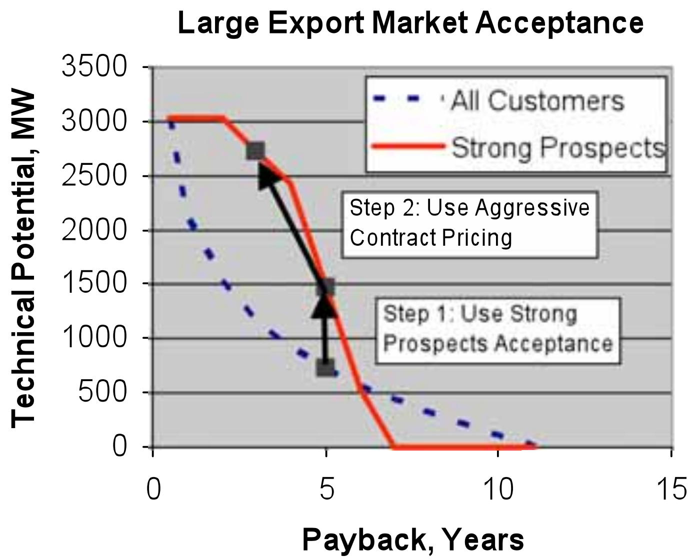
Export Market Issues

The large export market, greater 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 producers. The preliminary results of 671 MW were based on the assumption that the large customers would behave like the average customers and only about 25 percent 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 percent– or 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) are assumed to have about a 90 percent acceptance or about 2,700 MW.



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

Figure 35: Impact of Assumptions on Large Export Market Penetration

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 to 400 trillion / Btu per year but will reduce boiler fuel consumption by 50 to 143 trillion Btu / year.
- Average CHP load factor ranges from 75.6 to 82.6 percent, and effective CHP efficiencies range from 62 to 68 percent. The variation is due to the change in market shares for different types of CHP by scenario.
- Energy savings will range from 39 to 102 trillion Btu / year by the end of the forecast period.

Table 43: 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
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	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	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 percent load factor. Low load factor markets all operate 4500 hours per year or 51.4 percent load factor.
- CHP markets with cooling have the lowest effective CHP efficiency operating between 54-56 percent efficiency.33 On-site markets without cooling operate at an average 68 percent 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 percent load factor and a 73 percent CHP efficiency, making this market the highest contributor to energy output and energy savings.

[33] *Effective CHP efficiency* as 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.

Table 44: All-In Case Output Summary by Market Type

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/year)	92,218	1,706	61,472	31,572	212,820	399,788
Avoided boiler fuel (billion Btu/year)	35,872	730	11,929	6,270	88,546	143,346
Electricity Generated (million kWh)	10,103	167	6,722	3,287	24,676	44,955
Avoided Electricity for cooling (million kWh)	0	0	576	248	0	824
Total Electricity (million kWh)	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	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.

Avoided Central Station GHG Emissions Assumptions

The study team developed and presented a preliminary estimate of the avoided central station power emissions. In discussion at the meeting and in public comments afterwards there was criticism of the approach. A three-tier estimation of emissions was estimated depending on the CHP application load factor as follows (all on a delivered power basis including line losses):

- Baseload CHP–917 lb / MWh CO2
- Low load factor CHP–1100 lb / MWh
- Peak load air conditioning–1387 lb / MWh
- Exported CHP Power – 873 lb / MWh (at the generator, no line loss credit taken).

Each scenario has a different weighting of these individual market sectors, but the average value for avoided delivered power was approximately 950 lb / MWh.

This method was derived from assumptions about central station power components, efficiencies, and line losses as shown in **Table 45**. In order to focus attention on the performance of CHP and its ability to meet ARB targets for GHG reduction, this preliminary estimation of central power emissions was not used for the final calculation of GHG benefits. Rather, the ARB central station emissions number was used.

Table 45: Preliminary Estimate of Avoided Central Station GHG Emissions by Load Factor (Superseded)

Generator Heat Rates	**GT-CC Existing Btu/kWh**	**GT-CC New Btu/kWh**	**GT**
Heat Rate, LHV 59 F	6,369	5,950	8,900
Heat Rate, LHV 88 F			9,474
Heat Rate HHV as used	7,050	6,802	10,487

CHP System Load Factor	GT-CC Existing Share	GT-CC New Share	GT Share	Avg Heat Rate at Generator Btu/kWh HHV	T&D Losses	Avg Heat Rate Delivered Btu/kWh HHV	Avoided CO_2 Emissions lb/MWh
Baseload	42.5%	42.5%	15.0%	7,460	5%	7,833	917
Intermediate Load	25.0%	25.0%	50.0%	8,707	8%	9,403	1100
Avoided Electric Air Conditioning	0.0%	0.0%	100.0%	10,487	13%	11,851	1387
Export Baseload	42.5%	42.5%	15.0%	7,460	0%	7,460	873

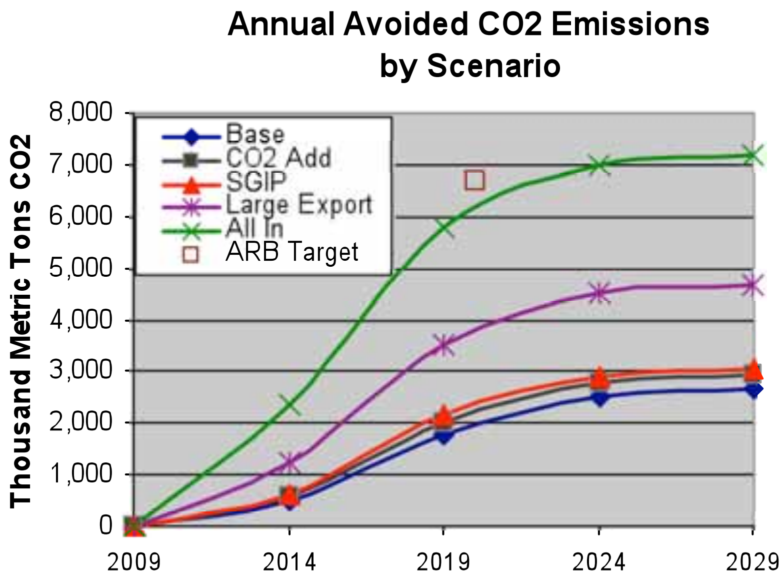
Source: ICF

The ARB estimated the avoided central power station emissions for its development of targets for CHP penetration in the Climate Change Scoping Plan. [34] The central station emissions assumed in the ARB study is 0.437 MT CO_2 / MWh or 963.4 lb / MWh. In addition ARB assumed line losses of approximately 8.5 percent raising the avoided emissions on a delivered basis to 1045 lb CO_2 / MWh.

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 reduction by 2020 is also shown on the graph.

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



Source: ICF CHP Market Model

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

Table 46 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 very similar to the "All In" Case defined for this study. In the *Base Case*, market penetration by CHP is only projected to be 56 percent of the ARB target estimate for additional CHP capacity market penetration, and actual power generation and avoided air conditioning from CHP is less than half of the ARB estimate. Finally, the emissions saving estimate is only 30 percent 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 percent of the target 2020 GHG emissions reduction.

Since, both the ARB and this study is 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 changes in the operating profile and performance for CHP. The differences between this analysis' GHG estimates and ARBs are as follows:

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

- Finally, there is one difference in the assumption regarding avoided central station emissions even using the ARB assumptions for this analysis. A total of 48 percent of the projected total market penetration in the "All-In" Case will be in CHP export markets. The power output from these CHP sources will need to travel through the utility grid system for delivery to other customers. Therefore, it is not appropriate to credit this generation with avoiding the delivered GHG emissions of 1045 lb / MWh as ARB did for all of their CHP power output; the appropriate comparison for export power is to the 963 lb / MWh generator emissions.

Table 46: Comparison of Study Results GHG Savings to ARB Target Estimate

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

Detailed tables of the model results showing detail by size, utility, and year are provided in ***Appendix C***.

4.0 Conclusions and Recommendations

The analysis showed that without further changes in CHP regulation or policy (*Base Case*) that 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 scoping 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 will range from 2.9 to 7.2 million MT of CO_2 equivalent by 2029–1.9 to 6.0 million MT of CO_2e by the ARB target date of 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 47** shows the comparison between large CHP and small CHP. Large CHP has 87 percent of the existing market penetration. Under *Base Case* Assumptions, however, only a very small amount of large CHP is expected to penetrate the market, about 10 percent of the total penetration for the *Base Case*. In the *"All-In" Case* there is a roughly even split between the market penetration for large and small CHP.

Table 47: 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

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 finalization of the AB 1613 Feed-in Tariff. In addition small CHP can profit from programs that reduce the cost of these systems and also 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 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 depend 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.

There also need to be ways to measure and account for the thermal energy utilization from facilities since it is the utilization of thermal energy that 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 only considers 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
Industrial	SIC 22: Textile Products					3	1.8									3	1.8
Industrial	SIC 24: Wood Products			1	44.0	2	51.0					13	185.8			16	280.8
Industrial	SIC 26: Paper					9	339.8			1	20.0	1	13.5			11	373.3
Industrial	SIC 27: Publishing					3	10.7							1	0.1	4	10.8
Industrial	SIC 28: Chemicals			1	108.0	13	160.1	1	1.9	2	81.8			5	12.2	22	364.0
Industrial	SIC 29: Petroleum Refining					11	839.5			5	311.0			1	51.0	17	1,201.5
Industrial	SIC 30: Rubber					1	0.5			1	27.0					2	27.5
Industrial	SIC 32: Stone, Clay, Glass					6	51.9							1	24.0	7	75.9
Industrial	SIC 33: Primary Metals					8	514.2									8	514.2
Industrial	SIC 34: Fabricated Metals					13	2.2									13	2.2
Industrial	SIC 35: Machinery					2	1.1									2	1.1
Industrial	SIC 36: Electrical Equipment					3	4.3	1	0.9							4	5.2
Industrial	SIC 37: Transportation Equip					3	13.1									3	13.1
Industrial	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
Other	SIC 01: Agriculture	1	25.0			11	22.0									12	47.0
Other	SIC 02: Livestock	2	0.9			1	2.5									3	3.4
Other	SIC 13: Crude Oil			3	124.7	70	2,379.1	3	8.9	2	0.4			2	35.5	80	2,548.5
Other	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
Commercial	SIC 4500: Air Transportation					3	45.0							1	0.5	4	45.5
Commercial	SIC 4800: Communications					6	27.6									6	27.6
Commercial	SIC 4939: Utilities	1	4.6			6	176.7			1	17.0			2	0.1	10	198.4
Commercial	SIC 4952: Wastewater Treatment	29	84.4			10	86.6							1	0.5	40	171.5
Commercial	SIC 4953: Solid Waste Facilites	7	18.8							1	35.6					8	54.4
Commercial	SIC 4961: District Energy	1	1.3			2	9.1									3	10.4
Commercial	SIC 5000: Wholesale/Retail					2	0.8									2	0.8
Commercial	SIC 5411: Food Stores					4	0.8									4	0.8
Commercial	SIC 5812: Restaurants					6	0.1							1	0.1	7	0.1
Commercial	SIC 6512: Comm. Building					45	32.6									45	32.6
Commercial	SIC 6513: Apartments					22	1.5							1	0.1	23	1.6
Commercial	SIC 7011: Hotels					65	33.6							3	0.6	68	34.2
Commercial	SIC 7200: Laundries					66	2.7							2	0.0	68	2.8
Commercial	SIC 7542: Carwashs					1	0.0									1	0.0
Commercial	SIC 7990: Amusement/ Rec.					50	59.7							4	0.7	54	60.4
Commercial	SIC 8051: Nursing Homes					19	2.9							2	0.1	21	3.0
Commercial	SIC 8060: Hospital/Healthcare	1	1.0			45	192.3									46	193.3
Commercial	SIC 8211: Schools					110	9.7							6	0.4	116	10.2
Commercial	SIC 8220: Colleges/Univ.	1	0.4			44	305.4							2	1.6	47	307.4
Commercial	SIC 8400: Zoos/Museums					1	1.4									1	1.4
Commercial	SIC 8900: Services NEC					31	9.0							1	0.0	32	9.0
Commercial	SIC 9100: Government Fac.					20	41.3							1	0.1	21	41.3
Commercial	SIC 9200: Courts/Prisons	1	37.0			14	71.8									15	108.8
Commercial	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 taken from the 2002 US Census of Manufacturing, available at: http://www.census.gov/econ/census02/guide/INDRPT31.HTM The Census of Manufacturing has information at the 6-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	NAICS code	MWh Demand/emp	NAICS code	MWh Demand/emp	NAICS code	MWh Demand/emp
326111	72.1	332115	48.7	333611	10.4	335999	11.2
326112	81.1	332116	16.0	333612	11.8	336111	34.8
326113	102.9	332117	51.7	333613	15.2	336112	36.6
326121	62.6	332211	27.8	333618	18.6	336120	14.9
326122	100.1	332212	17.8	333911	10.7	336211	9.8
326130	43.4	332213	26.9	333912	8.6	336212	9.8
326140	61.0	332214	26.5	333913	8.0	336213	5.5
326150	26.7	332311	9.4	333921	5.6	336214	5.6
326160	160.5	332312	13.6	333922	4.4	336311	33.6
326191	14.2	332313	16.8	333923	5.8	336312	33.8
326192	88.9	332321	10.5	333924	6.1	336321	26.1
326199	42.0	332322	9.7	333991	11.2	336322	16.1
326211	75.7	332323	9.0	333992	13.1	336330	30.9
326212	28.0	332410	19.5	333993	4.8	336340	29.2
326220	40.8	332420	15.7	333994	6.0	336350	33.8
326291	34.8	332431	106.3	333995	10.8	336360	14.0
326299	43.0	332439	20.0	333996	11.2	336370	23.4
327111	31.4	332510	14.2	333997	4.7	336391	65.2
327112	23.4	332611	28.4	333999	6.6	336399	22.9
327113	59.5	332612	15.4	334111	10.7	336411	12.8
327121	67.0	332618	16.8	334112	34.2	336412	23.0
327122	65.8	332710	13.8	334113	27.3	336413	22.8
327123	36.4	332721	16.4	334119	18.1	336414	13.6
327124	38.3	332722	23.4	334210	10.0	336415	29.1
327125	81.4	332811	71.3	334220	13.6	336419	35.0
327211	211.7	332812	37.9	334290	11.1	336510	13.9
327212	125.6	332813	29.8	334310	22.5	336611	12.1
327213	247.7	332911	21.8	334411	64.0	336612	6.8
327215	49.3	332912	18.3	334412	28.8	336991	14.8
327310	688.1	332913	26.2	334413	75.9	336992	21.3
327320	14.5	332919	25.3	334414	39.0	336999	11.3
327331	25.9	332991	49.8	334415	27.7	337110	11.1
327332	15.6	332992	30.4	334416	9.1	337121	7.9
327390	13.1	332993	23.7	334417	18.3	337122	17.7
327410	306.8	332994	14.5	334418	18.6	337124	12.3
327420	194.7	332995	22.8	334419	16.4	337125	21.3
327910	72.5	332996	15.6	334510	13.3	337127	13.3
327991	15.3	332997	12.3	334511	21.9	337129	17.1
327992	159.4	332998	24.3	334512	16.5	337211	14.8
327993	191.8	332999	21.5	334513	13.9	337212	10.6
327999	33.8	333111	8.1	334514	19.3	337214	19.0
331111	456.5	333112	7.6	334515	12.5	337215	16.1
331112	1,087.4	333120	10.7	334516	10.6	337910	9.3
331210	59.4	333131	7.8	334517	12.6	337920	8.2
331221	149.2	333132	11.3	334518	14.6	339111	10.7
331222	76.7	333210	6.3	334519	14.4	339112	15.4
331311	150.3	333220	7.1	334611	28.4	339113	14.6
331312	2,891.8	333291	6.3	334612	29.4	339114	10.7
331314	222.2	333292	6.9	334613	50.8	339115	23.7
331315	209.9	333293	9.9	335110	52.3	339116	4.1
331316	67.8	333294	5.5	335121	10.5	339911	6.2
331319	61.8	333295	8.7	335122	14.0	339912	15.9
331411	248.5	333298	6.0	335129	16.1	339913	6.9
331419	539.9	333311	5.7	335211	19.8	339914	6.3
331421	120.3	333312	4.9	335212	26.1	339920	14.2
331422	67.9	333313	3.7	335221	20.8	339931	7.9
331423	71.9	333314	7.6	335222	28.6	339932	18.8
331491	95.5	333315	10.2	335224	29.4	339941	23.9
331492	76.9	333319	4.5	335228	26.9	339942	22.1
331511	121.4	333411	5.5	335311	25.7	339943	10.4
331512	44.2	333412	6.9	335312	23.0	339944	14.6
331513	198.4	333414	6.5	335313	18.3	339950	9.6
331521	64.6	333415	8.2	335314	11.1	339991	27.2
331522	42.5	333511	9.3	335911	91.7	339992	11.4
331524	46.4	333512	7.8	335912	39.2	339993	40.9
331525	42.4	333513	6.1	335921	29.8	339994	12.7
331528	42.2	333514	9.0	335929	49.9	339995	13.1
332111	60.4	333515	9.3	335931	26.0	339999	11.8
332112	49.5	333516	11.3	335932	48.5		
332114	20.1	333518	5.5	335991	131.5		

Commercial

Information on MWh / employee figures were obtained from CEPD and CBECS to be used as control totals since these two sources did not provide the detail needed to represent all commercial and institutional applications. **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

Data from iMarket was used to determine MWh / employee figures 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).

- The iMarket screen included only businesses with 10 employees or greater

- The energy screen was done by exporting businesses in each MWH category from 50–99 up to >25,000. The mid-point of each energy bin was taken and divided by the average number of employees for each application to get the MWh per employee estimates.

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	500kW-1,000kW	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)	Annual Elect. Generated (million kWh)	Annual Avoided Elect. for cooling (million kWh)	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	78	5	4,908	1,551	538	14	1,032	55

South								
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	500kW-1,000kW	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)	Annual Elect. Generated (million kWh)	Annual Avoided Elect. for cooling (million kWh)	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	95	7	5,969	1,889	649	18	1,239	66

South								
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	500kW-1,000kW	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)	Annual Elect. Generated (million kWh)	Annual Avoided Elect. for cooling (million kWh)	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	86	6	5,356	1,694	590	16	1,168	62

South								
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	500kW-1,000kW	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)	Annual Elect. Generated (million kWh)	Annual Avoided Elect. for cooling (million kWh)	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	79	5	4,962	1,575	543	14	1,041	55

South								
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	500kW-1,000kW	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)	Annual Elect. Generated (million kWh)	Annual Avoided Elect. for cooling (million kWh)	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	110	7	6,802	2,181	746	19	1,473	78

South								
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