CONSULTANT REPORT

COMBINED HEAT AND POWER: POLICY ANALYSIS AND 2011 – 2030 MARKET ASSESSMENT

Prepared for: California Energy Commission

Prepared by: ICF International, Inc.

JUNE 2012

CEC-200-2012-002-REV

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ACKNOWLEDGEMENTS

The authors would like to thank Bryan Neff and Linda Kelly at the Energy Commission for their support and guidance during the entire project. The authors would also like to thank the following for information provided and specific comments made on draft materials:

California Energy Commission – Al Alvarado, Asish Gautam, Ruben Tavares

California Public Utilities Commission – Cem Turhal, Jennifer Kalafut

Air Resources Board – David Mehl, Gary Collord, Matthew Zaragoza-Watkins

DE Solutions – Keith Davidson

Alcantar & Kahl – Evelyn Kahl

California Cogeneration Council – Beth Vaughan

ABSTRACT

This report analyzes the potential market penetration of combined heat and power systems in California from 2011 to 2030. This analysis evaluates the potential contribution of new combined heat and power to the reduction in greenhouse gas emissions as required by the California Global Warming Solutions Act, Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006). The analysis characterizes the markets, applications, technologies, and economic competition for combined heat and power over the forecast period. A Base Case forecast of future combined heat and power market penetration is developed and assumes a continuation of current trends and energy policies. Two additional scenarios, Medium and High Cases, show the results of the implementation of additional combined heat and power stimulus policies.

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

Hedman, Bruce, Ken Darrow, Eric Wong, Anne Hampson. ICF International, Inc. 2012. *Combined Heat and Power: 2011-2030 Market Assessment*. California Energy Commission. CEC-200-2012-002.

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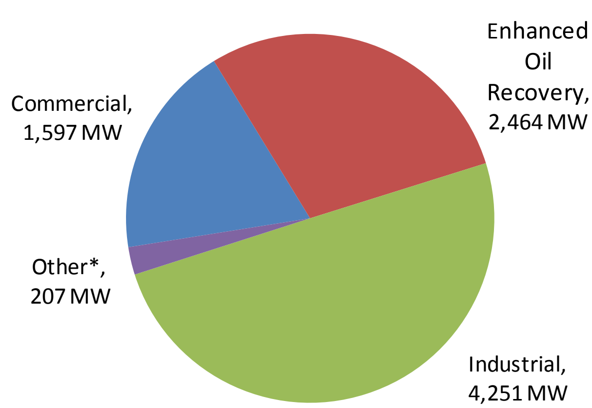
EXECUTIVE SUMMARY

This report quantifies the long-term market potential for combined heat and power (CHP) in California and the degree to which CHP can reduce potential greenhouse gas (GHG) emissions. Market penetration estimates of CHP are presented for three market development scenarios — a Base Case reflecting continuation of existing state policies and two additional cases (Medium and High) that show the market effects of additional CHP policy actions and incentives. This study represents an update of a similar analysis that the research team conducted in 2009.[1]

Existing Combined Heat and Power Capacity in California

There are a number of databases on existing CHP projects in California that are maintained by the utilities, the California Public Utilities Commission (CPUC), the Energy Commission, and the United States (U.S.) Energy Information Administration. ICF also maintains a database of existing CHP for the U. S. Department of Energy (DOE). The estimate of total existing CHP for California differs among each of these sources for a variety of reasons. ICF reviewed the major data sources to develop a reconciled list of all existing CHP systems in the state. Based on this reconciliation process, the project team estimates that there are currently 8,518 megawatts (MW) of active CHP in California at 1,202 sites as shown in **Figure ES-1**.

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



Source: ICF International, Inc.

Technical Potential for New Combined Heat and Power Capacity

The project team analyzed the industrial, commercial, institutional, and multifamily residential markets to quantify the remaining technical potential for CHP. The technical

1 Darrow, Ken Bruce Hedman, Anne Hampson, *Combined Heat and Power Market Assessment*, April 2010. ICF International, Inc., CEC-500-2009-094-F.

potential represents the sum of estimated new CHP capacity that could be built in applications that have the technical requirements (size, load factor, and thermal loads) necessary to support a potentially economic CHP project. The CHP sizing is based on the site thermal load. Applications, mostly in the industrial sector, with thermal-to-electric load ratios that are greater than one are sized to the thermal load and excess power exported to the grid. Applications where the thermal-to-electric load ratio is less than one will use all of their generated power on-site. A summary of the technical market potential is shown in **Table ES-1.** There are 14,293 megawatts (MW) of remaining potential in existing facilities and an additional 1,671 MW from expected business growth over the next 20 years. Of this total, 5,212 MW represents the portion of capacity that is for the export market. This capacity is heavily concentrated in systems larger than 20 MW.

Table ES-1: Technical Potential in Existing and New Facilities by System Size and Market Segment

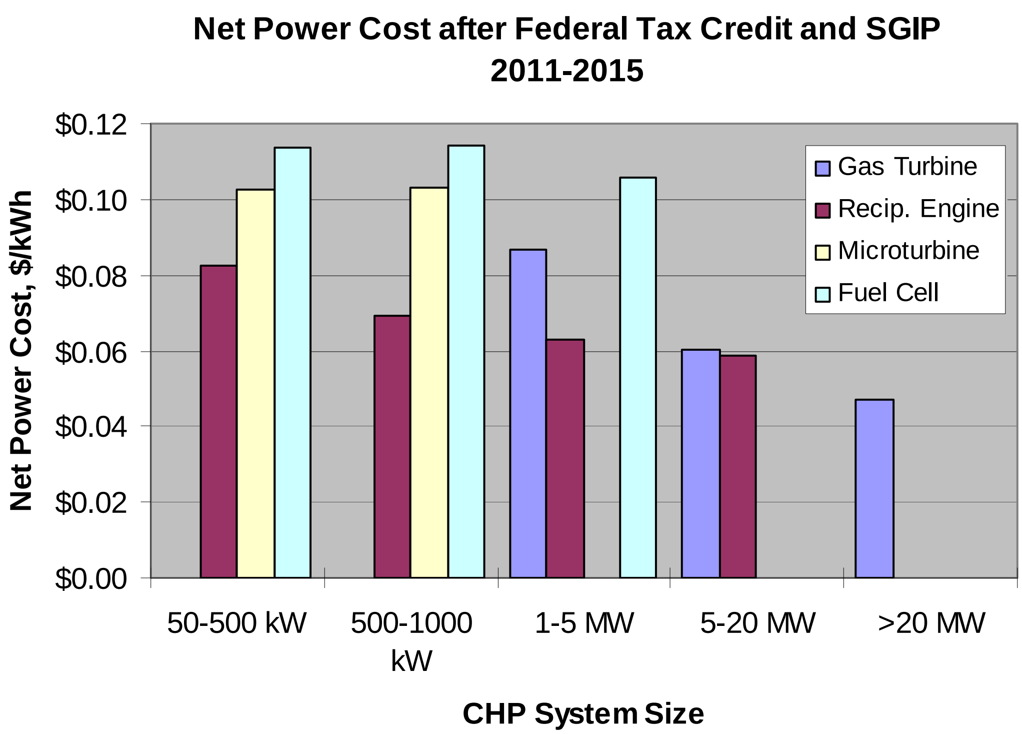
Market Type / Size Category	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW	Total
Remaining Technical Potential in Existing Facilities						
Industrial -- On-site	688	375	1,042	818	385	3,309
Commercial, Institutional, Government, Multifamily -- On-site	2,078	846	1,650	929	447	5,950
Export	0	0	286	901	3,847	5,034
Total – Existing Facilities	2,766	1,221	2,987	2,648	4,679	14,293
Technical Potential Related to New Facilities and Growth 2011-2030						
Industrial -- On-site	60	29	68	51	20	228
Commercial, Institutional, Government, Residential -- On-site	471	191	384	154	64	1,264
Export	0	0	9	40	131	180
Total – New Growth	531	220	461	245	215	1,672
Total	**3,297**	**1,441**	**3,439**	**2,893**	**4,894**	**15,965**

Source: ICF International, Inc.

Combined Heat and Power Technology Cost and Performance

The cost and performance of CHP technologies determine the economic competitiveness and market response. CHP economics are based on displacing purchased electricity and boiler fuel with self-generated power and thermal energy. To be economic, the savings in power and fuel costs need to be compared to the added capital, fuel, and other operating and maintenance costs associated with operating a CHP system. The project team evaluated the cost and performance of primary CHP technologies that are used in California including reciprocating internal combustion engines, microturbines, fuel cells, and gas turbines. The team analyzed 12 systems from 100 kilowatts to 40 megawatts in terms of capital cost including emissions after-treatment costs, electric efficiency, thermal output, nonfuel operating, and maintenance costs. **Figure ES-2** shows the estimated net power costs[2] for these systems using current energy prices. The figure shows that reciprocating engines are the least cost technology in sizes up to 5 MW. Above 5 MW, gas turbines are the most prevalent and most economic technology. The dominant technologies in each size range are competitive with current energy pricing in California. Emerging technologies such as microturbines and fuel cells have higher net power costs but receive some market share as a result of other benefits such as low emissions, technical innovation, and, in the case of fuel cells, higher incentives.

Figure ES-2: CHP Net Power Costs by System Size and Technology



Source: ICF International, Inc.

2 Net power costs represent the sum of the levelized amortized capital costs at 10 percent return, the operating and maintenance costs, and the net increase in fuel costs after avoided boiler fuel is subtracted – on a dollars-per-kilowatt basis. The resulting value is equal to the avoided cost of power that would provide a 10 percent rate of return.

Market Penetration Scenario Assumptions

The project team analyzed market penetration of new CHP facilities over a 20-year time horizon (2011-2030). The Base Case reflects policies as they are expected to be implemented under current and emerging regulations as follows:

- **Qualifying Facility / Combined Heat and Power Settlement Agreement** – CPUC Decision 10-12-035, December 21, 2010, resolved outstanding disputes between utilities and qualifying facilities and established a new CHP procurement program through 2020. While primarily focused on existing CHP, some terms and capacity limitations of the settlement affect the outlook for new CHP projects wanting to export power to the grid. The Short Run Avoided Cost Pricing mechanism adopted under the settlement agreement was used to represent the price paid for export power from projects larger than 20 MW.
- **CHP Export Feed-in-Tariff** – Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007) provides a price for the sale of excess power to a utility from CHP facilities less than 20 MW.
- **Self-Generation Incentive Program** – Senate Bill 412 (Kehoe, Chapter 182, Statutes of 2009) revises and extends the program by adding back non-fuel cell CHP technologies and provides funding through December 31, 2015.
- **33 Percent Renewables Portfolio Standard** – Most recently modified by Senate Bill 2 (Simitian, Chapter 1, Statutes of 2011), and CPUC proceeding R.11-05-005, it requires utilities to have 33 percent of their generating capacity based on retail sales be renewable power by 2020.
- **Cap and Trade** – The California Global Warming Solutions Act (Assembly Bill 32, Núñez, Chapter 488, Statutes of 2006) establishes a market trading program for carbon dioxide emissions allowances that is designed to bring state emissions of greenhouse gases down to 1990 levels by 2020.

The Medium and High cases show the added CHP market penetration that can be achieved with additional policy measures as follows:

Medium Case

- Legislative extension of the Self-Generation Incentive Program beyond December 31, 2015, with programmed phased reduction in incentives until the payments decrease to zero.
    - 5 percent reduction per year for all CHP technologies except fuel cells.
    - 10 percent reduction per year for fuel cells until the incentive dollar value equals the value of other CHP technologies – then all technologies decline at the same 5 percent rate.

- Large export markets (greater than 20 MW) require:
    - Pricing based on the 2011 Market Price Referent, 25 – 35 percent higher than Base Case.[3,4]
    - Higher market response for paybacks less than five years.
- An increase in market participation rates in model analysis by 5 – 20 percent due to reduction in perceived market risk.

High Case

- Cap-and-trade allowance costs for CHP fuel consumption, after avoided boiler fuel is subtracted and is reimbursed, eliminating the effective rise in natural gas fuel costs due to the Cap-and-Trade Program. In all cases, it is assumed that cap and trade-related electric price increases are reimbursed on a 90 percent basis.
- Increased focus on power production from export projects by using combined cycle power generation technology for potential export projects over 50 MW. This change increases the large export technical potential from 3,567 to 5,401 MW — more than a 50 percent increase.
- Standby power cost mitigation – investor-owned utilities eliminate nonbypassable charges that are currently applied to CHP and revise rates that require customers with CHP to pay both a standby reservation demand charge and additional demand charges for outages of the customer's generator. This change increases the savings from avoided electricity purchases by 1 – 2 cents per kilowatt-hour.
- Ten percent California investment tax credit is applied to CHP investments with no time limit or size restriction.
- Capital Cost Reduction – an additional 10 percent reduction in capital costs by 2030 that reflects the effect that higher market penetration will have on technology improvements, turnkey design, and improved installation and interconnection practices.
- $50 a kilowatt per year for transmission and distribution capacity deferral payments for CHP systems less than 20 megawatts
- An increase in market participation rates in model analysis by an additional 2 – 7 percent compared to the Medium Case.

Market Penetration Scenario Results

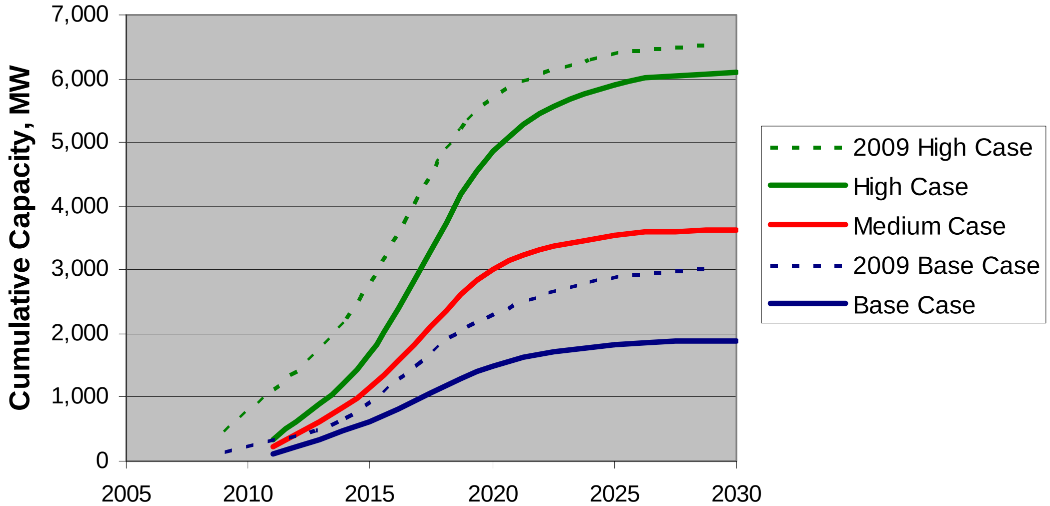
Cumulative market penetration for new CHP capacity for the three scenarios is shown in **Figure ES-3** and **Table ES-2**. The 2011 20-year cumulative CHP market penetration ranges

3 Resolution E-4442, California Public Utilities Commission, December 1, 2011.

4 2011 Market Price Referent Calculation Model: http://www.cpuc.ca.gov/NR/rdonlyres/B4F07AB3-0846-403B-ADDD-E6F495826113/0/Final2011MPR.xls.

from 1,888 MW in the Base Case to 6,108 MW in the High Case. The figure and table also compare the 2011 scenario forecast with the Base and High cases from the 2009 CHP market assessment.

Figure ES-3: Cumulative Market Penetration by Scenario



Source: ICF International, Inc.

Table ES-2: Cumulative Market Penetration by Scenario

2011 Scenarios	Cumulative New CHP Market Penetration, MW				
	2011	2015	2020	2025	2030
Base Case	123	617	1,499	1,817	1,888
Medium Case	233	1,165	3,013	3,533	3,629
High Case	340	1,700	4,865	5,894	6,108
2009 Scenarios	**Cumulative New CHP Market Penetration, MW**				
	2009	**2014**	**2019**	**2024**	**2029**
Base Case	136	680	2,096	2,816	2,998
High Case (All-in)	442	2,209	5,338	6,306	6,519

Source: ICF International, Inc.

The 2011 market scenarios, in general, show lower cumulative market penetration than the 2009 scenarios. There are a number of contributing factors:

- The economic slowdown has reduced technical market potential, there are fewer existing businesses in California with CHP potential, and the growth expectations for those markets over the next 20 years are lower.
- The current CHP technology installation and capital costs used in the analysis have increased.

- The CHP feed-in-tariffs as now developed and used in this analysis are lower.
- Export pricing for AB 1613 eligible projects had not been developed in 2009, so the 2009 analysis was based on the renewable feed-in-tariff that included a significant component related to avoidance of GHG emissions.
- The difference between gas and electric prices, often called the "spark spread," is somewhat more favorable now than in 2009 due to a more favorable supply outlook for natural gas, but the benefits of lower gas costs is somewhat offset by GHG costs due to cap and trade.
- Cap and trade was not included in the 2009 assumptions.

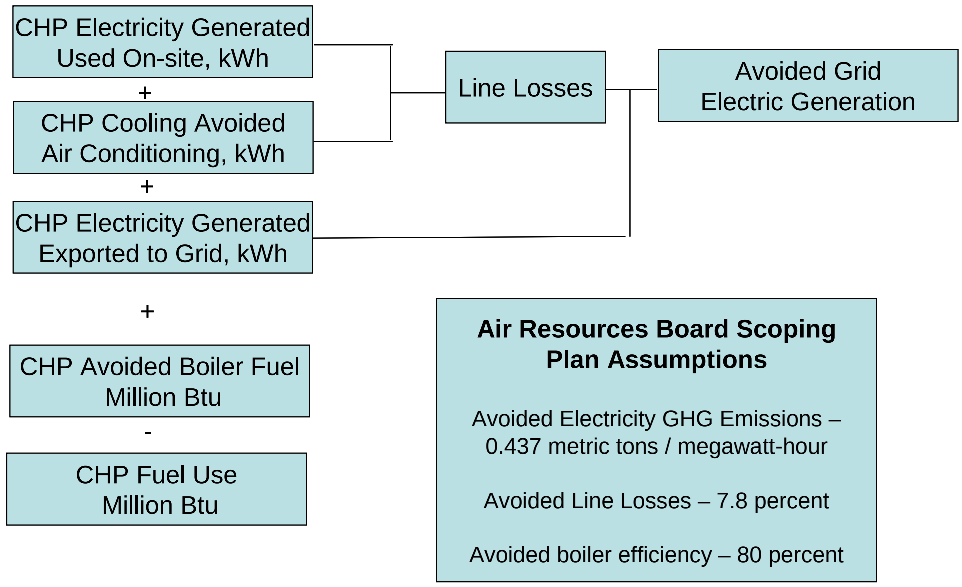
The Self-Generation Incentive Program is more inclusive than in the 2009 analysis, but the stimulation of market penetration in the Base Case is limited by the program's current expiration date of 2016. The program is approved by the CPUC and provides financial incentives for installing clean, efficient, on-site distributed generation to qualifying facilities in the three investor-owned utilities' service territories.

Greenhouse Gas Emissions Reduction From New Combined Heat and Power

The contribution of CHP to statewide reductions in greenhouse gas emissions is the principal motivation for this market assessment and identification of policy measures that will increase CHP market penetration.

To provide an estimate that could be compared to the *California Air Resources Board (ARB) Scoping Plan (Scoping Plan)*, the team used the ARB assumptions for avoided emissions as shown in **Figure ES-4**. The ARB assumptions for avoided generation emissions, electric line losses, and avoided boiler efficiency are shown in the figure. The electric and thermal performances of CHP systems were taken from the multisector outputs of the ICF CHP Market Model. Each market sector has its own performance and output factors.

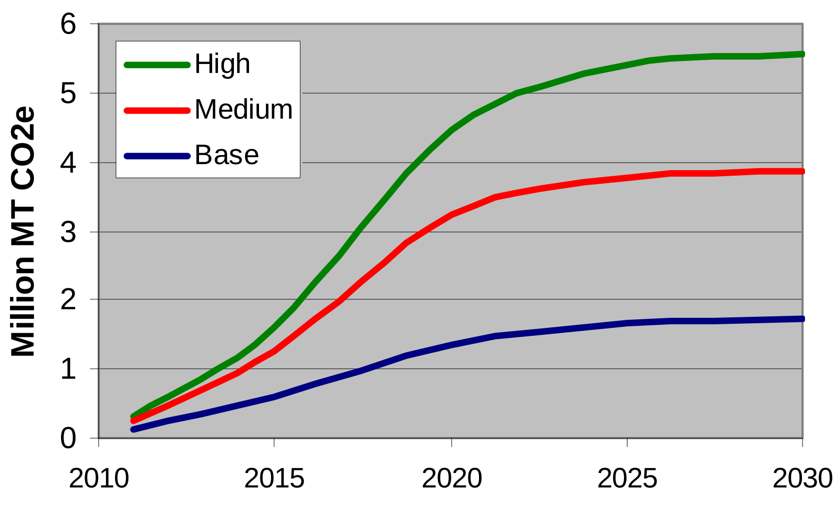
Figure ES-4: Estimation Procedure for Greenhouse Gas Emissions Reduction From CHP



Source: ICF International, Inc.

The avoided annual greenhouse gas emissions on this basis range from 1.4 million to 4.5 million metric tons in 2020 and 1.7 million to 5.6 million metric tons by 2030, as shown in **Figure ES-5**.

Figure ES-5: Greenhouse Gas Emissions Reduction From CHP Compared to Current Emissions

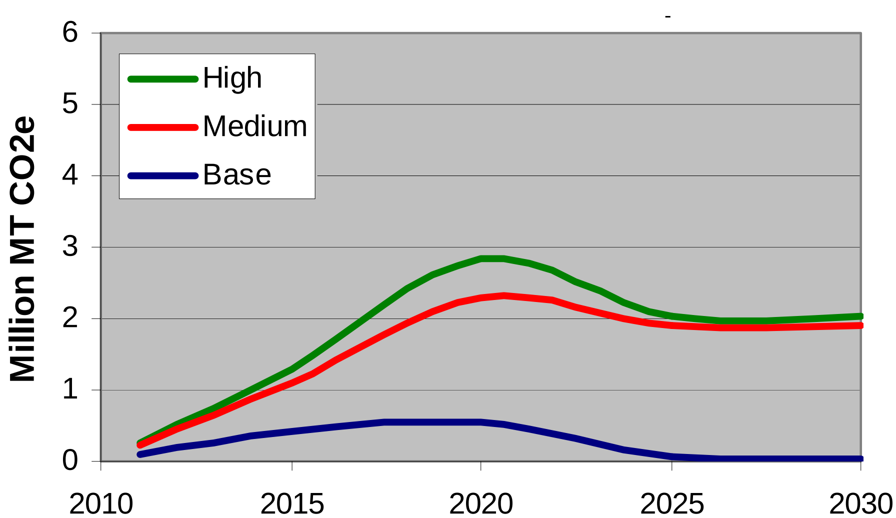


Source: ICF International, Inc.

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

Figure ES-6 shows the valuation of greenhouse gas emissions savings over time with the Renewables Portfolio Standard in place. Medium and High Case reductions are less than the Base Case because, as noted, export market penetration does not reduce the greenhouse gas emissions savings. The export market is much higher in the Medium and High Cases.

Figure ES-6: Greenhouse Gas Emissions Savings From Combined Heat and Power With 33 Percent Renewables Portfolio Standard



Source: ICF International, Inc.

Conclusions

The Base Case results show that, under the current policy landscape, CHP will fall short of the ARB *Scoping Plan* market penetration target. Additional policy measures, represented in the Medium and High Cases, are needed to raise market penetration up to the *Scoping Plan* target.

As noted, the 2011 CHP market assessment shows lower cumulative market penetration than the 2009 market assessment due to the following factors:

- Reduced economic activity
- Higher CHP system installed costs
- Lower assumed export pricing under AB 1613
- Effective increases to natural gas costs resulting from the cost of allowances under cap and trade
- Early ending or phased reduction of incentives under the Self-Generation Incentive Program

The markets for large and small CHP systems have different needs and respond to different types of incentives. **Table ES-3** provides the breakdown of 20-year cumulative market penetration by scenario for large (greater than 20 MW) and small (less than 20 MW) systems.

Table ES-3: Cumulative Market Penetration by Market for Large and Small Systems

Scenario	Base		Medium		High	
Size	< 20 MW	> 20 MW	< 20 MW	> 20 MW	< 20 MW	> 20 MW
On-site	1,269	246	1,519	263	2,901	388
Avoided Air Conditioning	130	30	155	32	316	45
Export	91	122	93	1,568	295	2,162
Total	**1,489**	**399**	**1,766**	**1,863**	**3,513**	**2,595**

Source: ICF International, Inc.

Small capacity markets respond to the Self-Generation Incentive Program, transmission and distribution deferral payments, electric rate increases caused by implementation of the Renewables Portfolio Standard, and CHP system cost reductions over time as the market matures. Large capacity markets respond mainly to the export price. All markets benefit from investment tax credits. Small markets, primarily, are negatively affected by costs associated with cap and trade; large export markets can recover those costs by bundling them with the cost of power or passing them on to the utility.

Table ES-3 also shows how important stimulation of the export market is to achieving the high levels of market penetration forecast under the Medium and High Cases. In the Base Case, the export market additions of new CHP are only 213 MW. In the High Case with higher pricing signals, the market growth increases to 2,457 MW. Prices approaching the full long-run marginal cost of power are needed for significant penetration of new large CHP export projects – not short-run avoided cost. Smaller, AB 1613-eligible projects have higher costs, making it difficult to compete even with the utility long-run marginal cost provided.

The export analysis in this project was based on setting the price for export and letting the market model solve for the quantity of market penetration. In December 2010, the CPUC convened a series of settlement meetings to resolve disputes between CHP stakeholders and the three investor-owned utilities. After 18 months, a proposed settlement was approved by the CPUC that set a CHP export target of 3,000 MW with the price being determined by a bidding process. The 3,000 MW target could be fully subscribed by existing CHP systems. After the 3,000 MW target is met, the CPUC will determine the need for new targets. Therefore, achieving the levels of market penetration for new export CHP defined under the Medium and High Cases will depend on the targets for CHP capacity the CPUC sets in the future.

The GHG emissions savings from CHP are smaller than the ARB scoping target of 6.7 million metric tons per year of carbon dioxide even in the High Case, where market penetration exceeds the ARB estimate. The reasons for this difference stem from the nature of the CHP markets themselves. In the *Scoping Plan*, all the CHP market penetration was assumed to be in large markets from systems that are 20 MW or larger. These systems operate almost continuously day and night, throughout the year, using all the excess heat they generate. In this analysis, utilization of the excess heat for the small markets, which include systems below 20 MW, were assumed to be only 80 percent. Larger markets were assumed to have 90-100 percent utilization of excess heat. In addition, markets that use a portion of the available excess heat to replace electric air conditioning have much lower emissions savings than those that strictly replace boiler fuel. Low load factor markets also save less due to their reduced annual hours of operation.

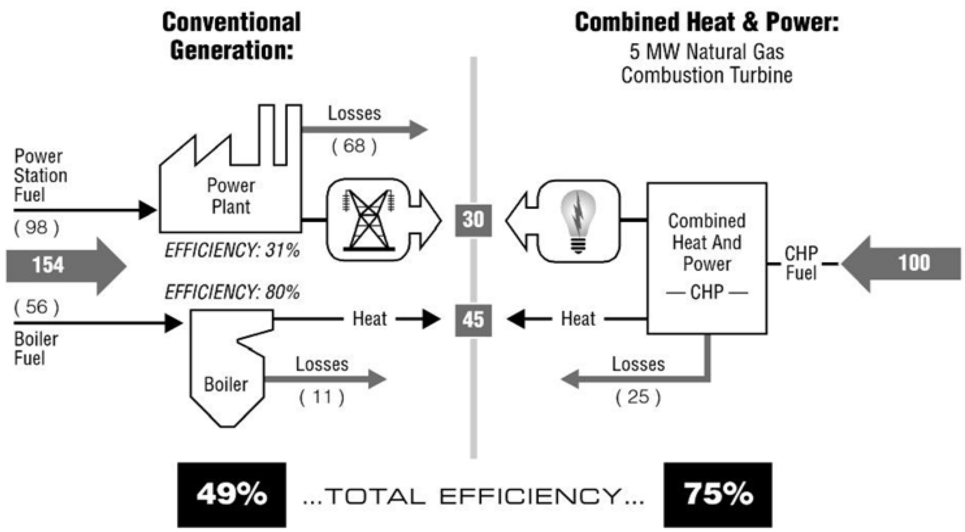
Concurrent carbon reduction programs will reduce the marginal greenhouse gas savings over time as the California energy economy becomes less dependent on fossil fuels. However, this will be true for all measures in the *Scoping Plan*. The focus in comparing the efficacy of measures to reduce GHG emissions should be on cost-effectiveness. CHP is less costly than some renewable energy sources providing equivalent emission reductions.

Finally, CHP saves money for the facilities that adopt it. This is the motivation that drives customer adoption. By 2030, CHP would save customers $740 million per year in energy costs under the Base Case and $2.9 billion per year under the High Case. Measures that provide a mechanism to bring societal benefits such as GHG emissions reduction, transmission and distribution capacity deferral, and energy efficiency into the private investment decision will increase market penetration for CHP, as shown by the market response in the Medium and High Cases analyzed.

CHAPTER 1: Introduction

Combined heat and power (CHP), also known as cogeneration, produces electricity and useful thermal energy in an integrated system. CHP systems can range in size from hundreds of megawatts such as those being operated at refineries and in enhanced oil recovery fields down to a few kilowatts that are used in small commercial and even residential applications. As shown in **Figure 1**, combining electricity and thermal energy generation into a single process can save 35 percent of the energy required to perform these tasks separately.

Figure 1: Combined Heat and Power Efficiency



Source: ICF International, Inc.

In 2006, California committed to reducing its greenhouse gas[5] (GHG) emissions to 1990 levels by 2020 by passing Assembly Bill 32 (AB 32), the *Global Warming Solutions Act of 2006* (Núñez, Chapter 488, Statutes of 2006). AB 32 set the stage for moving the California economy toward a sustainable, clean energy future. As the lead agency responsible for implementing AB 32, the California Air Resources Board (ARB) prepared a comprehensive *Scoping Plan* that identified a multipronged approach to meeting this goal.[6] In this plan, the ARB recognized CHP as an important component of the overall GHG emissions reduction

5 There are a number of gases classified as "greenhouse gases" including carbon dioxide, methane, and nitrous oxide. This analysis considers only the effect on carbon dioxide, the principal GHG produced from the deployment of CHP.

6 *Climate Change Scoping Plan: A Framework for Change*, California Air Resources Board, December 2008.

strategy. The ARB also recognized the need for public policies to eliminate market and other barriers that are keeping CHP from reaching its full market potential.

This report presents the results of a comprehensive CHP market assessment undertaken for the California Energy Commission to identify expected CHP market penetration assuming that existing regulatory policies affecting CHP are continued. In addition, the project team analyzed the potential market penetration that could be achieved with additional incentives and regulations aimed at removing market barriers or providing incentive mechanisms for recognizing the economic and environmental benefits of CHP that are currently not captured in the customer's economic CHP implementation decision.

This assessment is an update of two prior CHP market assessments conducted in 2005[7] and 2009[8]. The update identifies how current economic conditions and regulations have changed the future outlook for CHP.

This report includes the following sections:

- CHP Market Characterization
  - 2011 Policy Landscape
  - Existing CHP
  - CHP Technical Market Potential
  - Natural Gas and Electricity Pricing
  - CHP Technology Cost and Performance
- CHP Market Forecast and Scenario Analysis
  - Scenario Assumptions
  - Scenario Results
- Conclusions

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

8 *Combined Heat and Power Market Assessment*, ICF, International, CEC-500-2009-094-F, April 2010.

CHAPTER 2: CHP Market Characterization

2011 CHP Policy Landscape

The combined heat and power (CHP) policy landscape changed dramatically for both large and small CHP systems since the 2009 report.[9]

- In 2010 and 2011, the California Public Utilities Commission (CPUC) issued decisions affecting all Public Utility Regulatory Policies Act (PURPA) qualifying facilities (QFs) in California. The resulting CHP *QF Settlement Agreement* (*QF Settlement*) establishes a new state CHP program, replacing the California PURPA program for CHP facilities greater than 20 MW.
- Four relevant statutes were also codified:
  - Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007) (AB 1613) allows for the sale of excess power to a utility from CHP facilities.
  - Assembly Bill 2791 (Blakeslee, Chapter 253, Statutes of 2008) (AB 2791) added federal, state, and local government CHP facilities to the AB 1613 program.
  - Senate Bill 412 (Kehoe, Chapter 182, Statutes of 2009) (SB 412) revised the state's Self-Generation Incentive Program (SGIP).
  - Assembly Bill 1150 (Pérez, Chapter 310, Statutes of 2011) (AB 1150) extended the SGIP fund collection that would have ended December 31, 2011, to December 31, 2014, and maintained the administration of the fund through January 1, 2016.
- Regulatory actions and related matters include:
  - The standby exemption for CHP under 5 MW ended June 1, 2011.
  - The California Air Resources Board (ARB) adopting its Cap-and-Trade Program for the establishment, administration, and enforcement of a greenhouse gas allowance budget on covered entities and provided for a trading mechanism for compliance instruments (October 2011).
  - The CPUC, in anticipation of the ARB Cap-and-Trade Program, issuing an Order Instituting Rulemaking (OIR, R11-03-012) on March 30, 2011, to address the use of revenues generated from the sale of GHG emissions allowances allocated to the electric utilities by the ARB. The rulemaking is to end 18 months from the initiation of the OIR.
  - The CPUC initiating the Distribution System Interconnection Settlement (DSIS) process on August 19, 2011, to allow stakeholders a confidential forum to develop a

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9 *Combined Heat and Power Market Assessment,* ICF, International, CEC-500-2009-094-F, April 2010.

revised Rule 21 that addresses the interconnection issues associated with projects that will be exporting all or part of their power.

- Nonbypassable surcharges on customer bills and their effect on CHP economics become of interest.

Each of these events is summarized, and their effects on CHP economics are addressed below.

QF Settlement

On October 8, 2010, after more than a year-and-a-half of intensive negotiations, the three investor-owned utilities (IOUs), four representatives of QFs, and two ratepayer advocacy groups filed the *Qualifying Facility and Combined Heat and Power Program Settlement Agreement (QF Settlement).*[10] The CPUC quickly approved the settlement (Decision 10-12-035, December 16, 2010). The *QF Settlement*, except for the continuance of a PURPA program for QFs 20 MW or less, provides for a state CHP program as a replacement for the federal PURPA program. Federal Energy Regulatory Commission (FERC) approval of the elimination of the must-take obligation for the non-PURPA program was issued on June 16, 2011.[11] Noteworthy is the following from the CPUC Decision:

> The Proposed Settlement is comprehensive. It would resolve numerous outstanding QF issues involving disputes in several Commission [sic], and provide for an orderly transition from the existing QF program to a new QF/Combined Heat and Power (CHP) program. This new program is designed to preserve resource diversity, fuel efficiency, GHG emissions reductions, and other benefits and contributions of CHP. The Proposed Settlement is also designed to promote new, lower GHG-emitting CHP facilities and encourage the repowering, operational changes through utility-pre-scheduling, or retirement of existing, higher GHG-emitting CHP facilities. Additionally, the Commission finds that the Proposed Settlement provides for an appropriate allocation of the costs of the QF/CHP program to all customers in California who benefit from the

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10 Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, the California Cogeneration Council, the Cogeneration Association of California, the Energy Producers and Users Coalition, the Independent Energy Producers Association, the Division of Ratepayer Advocates of the California Public Utilities Commission, and The Utility Reform Network.

11 Docket No. QM11-2-00.

> CHP portfolio. The Proposed Settlement is comprehensive, but it does not resolve issues in numerous Commission proceedings implementing recent statutory requirements that pertain to QFs of 20 MW or less, such as new CHP systems under Assembly Bill 1613 (codified as Pub. Util. Code sections 2840-2845), except to acknowledge that the megawatt (MW) and GHG reductions will count toward the investor-owned utilities' MW and GHG reduction targets.

The *QF Settlement* establishes a new state CHP program with a number of key objectives and goals.[12] Significantly, it sets a procurement target of 3,000 MW of CHP, and a GHG emissions reduction target for the IOUs, electric service providers (ESPs), and community choice aggregators [13](CCAs) of 4.8 million metric tons (MMT).[14] These targets will be achieved through the procurement of efficient CHP.

The *QF Settlement*, in transitioning from the federal program to a state CHP program, enables a CHP facility, when nearing the expiration of its current power purchase agreement (PPA) to consider a number of options. For example, the CHP owner/operator could obtain a new PPA, sell into the wholesale market, shut down, or cease to export. The *QF Settlement* included several standard form contracts for existing and new CHP including:

- Transition PPA with avoided cost pricing for an existing QF with an expired or expiring PPA.
- CHP request for offer (RFO) pro-forma PPA for new or existing facilities 5 MW and larger that bid into a utility CHP-only RFO and win.
- PURPA QF PPA for new and existing facilities 20 MW or less.
- Ooptional CHP PPA for eligible as-available facilities.
- Amendment for existing legacy QF contracts.

New and repowered facilities are eligible for a 12-year PPA but will need to meet additional criteria. There are also two PPAs for QFs under PURPA that qualify for an AB 1613 contract, including one for QFs 20 MW and below and one for QFs 5 MW and below as a simplified

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12 Section 1, CHP Program Settlement Agreement Term Sheet, dated October 8, 2010.

13 Community choice aggregation allows customers to aggregate, or combine, their electrical loads as members of their local community with community choice aggregators. See SB 117, Chapter 838, Filed with Secretary of State on September 24, 2002. [http://www.leginfo.ca.gov/pub/01-02/bill/asm/ab_0101-0150/ab_117_bill_20020924_chaptered.pdf.](http://www.leginfo.ca.gov/pub/01-02/bill/asm/ab_0101-0150/ab_117_bill_20020924_chaptered.pdf)

14 This is based on the statewide ARB Combined Heat and Power Recommended Reduction Measure of 6.7 MMT, as described in the *ARB Scoping Plan*.

contract. Existing CHP resources that expand or repower that meet the criteria could be eligible for the different PPAs.[15]

For this update, the focus is on the following PPAs that would add capacity above existing QF/CHP and would count toward the MW target and GHG emissions reduction target under the *QF Settlement*.

PPAs for AB-1613 CHP 20 MW and Below

New or repowered CHP that meet the technical requirements of AB 1613 are eligible to receive a feed-in-tariff (FIT) administered by the CPUC. The FIT is issued annually. The fixed charge paid is locked-in per the PPA term start date. The volumetric or energy charge varies year to year and is adjusted for season of delivery, time-of-day delivery, gas price at utility's specified physical natural gas delivery location, and a location bonus. The price offered under the AB 1613 contracts is based on the costs of a new combined cycle gas turbine, and a location bonus shall be applied to eligible CHP systems located in local reliability areas. The details of the AB 1613 pricing are described in detail in the section "Natural Gas and Electricity Pricing," later in this chapter.

PPAs for AB 1613 CHP 5 MW and Below (Simplified Contract)

New or repowered CHP 5 MW and below that meet the technical and legal requirements of AB 1613 qualify for a simplified contract and the CPUC-administered FIT. The fixed charge paid is locked-in per the PPA term start date. The volumetric or energy charge varies year to year and is adjusted for season of delivery, time-of-day delivery, gas price at utility's specified physical natural gas delivery location, and a location bonus. The price offered under the AB 1613 contracts is based on the costs of a new combined cycle gas turbine, and a location bonus shall be applied to eligible CHP systems located in local reliability areas.

AB 1613 and AB 2791 – Export of CHP

The two statutes seek to increase participation in CHP development from traditional commercial and industrial customers, nontraditional customers that would ordinarily not budget for such projects: nonprofits and federal, state, and local governments. For the nontraditional customers, the CPUC is to establish a pilot pay-as-you-save program for CHP systems not exceeding 20 MW in size. The program would use on-bill financing, where the customer would have the capital and installation costs of a CHP system repaid by the difference between what would have been paid for electricity and the actual savings derived for a period of up to 10 years. The pilot program has a 100 MW participation cap that is proportionately shared among the three IOUs based on contribution to the state's peak demand. The CPUC decided not to move ahead after finding a lack of interest in the

15 These would include AB 1613 PPA, less than 20 MW PURPA PPA, RFO PPA and potentially others. Per Jennifer Kalafut, CPUC, e-mail, October 20, 2011.

program from affected customers and complexities such as risks to ratepayers and application of federal and state lending laws in implementing the program.[16]

Self-Generation Incentive Program

In the wake of the 2000 – 2001 electricity crisis that saw electrical outages throughout California, the Legislature directed the CPUC to initiate certain load control and distributed generation program activities, including financial incentives to eligible customers.[17] The SGIP was established to encourage the development and commercialization of new distributed generation[18] (DG) technologies.[19] With the enactment of the California Solar Initiative in 2006,[20] solar technology moved out of the SGIP into its own program. Today, the SGIP is recognized as one of the largest funded and longest running DG incentive programs in the country.

Since the program's inception, CHP was included as an eligible technology. Beginning January 1, 2005, combustion-based CHP using fossil fuel was required to meet a stringent nitrogen oxide (NO_x) limit of 0.14 lb/megawatt hour (MWh), and on January 1, 2007, meet the "ARB 2007" NO_x limit of 0.07 lb/MWh, regarded as the most stringent standard worldwide.[21] In 2006, the program was extended from January 1, 2008, to January 1, 2012, but limited eligibility to only wind and fuel cells.[22] In 2008, a California-based manufacturer became eligible for a 20 percent additional incentive.[23]

In 2009, the CPUC was authorized to determine, in consultation with the ARB, what technologies should be eligible for the SGIP based on GHG emissions reductions.[24] In addition, the expiration date of the SGIP was extended from January 1, 2012, to January 1, 2016. The long-awaited CPUC decision implementing the law was issued on September 8, 2011.[25] However, with the fund collection's rapid depletion in 2010 and funding to end December 31, 2011, the DG industry sponsored legislation that was enacted September 22,

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16 Decision 11-01-010, January 13, 2011.

17 Assembly Bill 970 (Alpert, Bowen, Kelley, Chapter 329, Statutes of 2000) (AB 970).

18 Distributed generation is electricity production that is on-site or close to the load center and is interconnected to the distribution system.

19 Decision 01-03-073. March 21, 2001.

20 Senate Bill 1 (Murray, Chapter 132, Statutes of 2006) (SB 1).

21 Assembly Bill 1685 (Leno, Chapter 894, Statutes of 2003) (AB 1685).

22 Assembly Bill 2778 (Lieber, Chapter 617, Statutes of 2006) (AB 2778).

23 Assembly Bill 2267, (Fuentes, Chapter 537, Statutes of 2008) (AB 2267).

24 Senate Bill 412 (Kehoe, Chapter 182, Statutes of 2009) (SB 412).

25 Decision 11-09-015. September 8, 2011.

2011, extending fund collection of about $83 million per year for three years to December 31, 2014.[26]

CHP developers who put projects on hold since the passage of SB 412, effectively a two-year period, were notified by the CPUC that they could begin submitting applications consistent with utility *SGIP Handbook* forms beginning November 15, 2011. With natural gas forecast to be stable through 2030,[27] CHP systems are expected to be competitive with other eligible technologies.

The latest SGIP is distinguished from its predecessors as being budget-weighted to renewables vs. nonrenewable fuel technologies (75 percent vs. 25 percent). The hallmark of this SGIP is its hybrid performance-based incentive (PBI) with payments keyed to GHG compliance. Fifty percent of the eligible incentive is paid up front. The remaining 50 percent is paid over 5 years with the payment based on performance. The capacity factor differs for each technology, 10 percent for advanced energy storage, 25 percent for wind, and 80 percent for all other technologies. Payment pivots off of GHG performance:

- A 5 percent exceedance band for GHG above 398 kilograms CO_2/MWh (877 pounds per megawatt hour [lb/MWh])
    - Half the payment in years where the emission rate is between 398 kilograms/megawatt hour (kg/MWh) and 417 kg/MWh (918.5 lb/MWh).
    - No payment in any year in which the emission rate is greater than 417 kg/MWh.

Other notable features include:

- A minimum efficiency of 62 percent higher heating value (HHV) for CHP systems.
- Tiered incentive for the first 3 MW, with decline beginning January 1, 2013, at 5 percent for conventional CHP:
    - First MW at 100 percent
    - Second MW at 50 percent
    - Third MW at 25 percent
- Manufacturer's credit = unadjusted incentive (50 cents) x 1.2 for California manufacturers.
- Export to Grid: 25 percent maximum of nameplate on an annual net basis.

The incentive levels by technology are shown in **Table 1.**

26 Assembly Bill 1150 (Pérez, Chapter 310, Statutes of 2011) (AB 1150).

27 ICF internal gas price forecasts.

Table 1: SGIP Incentive Categories and Levels

Technology Type	Incentive ($/W)
Renewables and Waste Heat	
Wind Turbine	$1.25
Bottoming-Cycle CHP	$1.25
Pressure Reduction Turbine	$1.25
Conventional CHP	
Internal Combustion Engine – CHP	$0.50
Microturbine – CHP	$0.50
Gas Turbine - CHP	$0.50
Emerging Technology	
Advanced Energy Storage[1]	$2.00
Biogas[2]	$2.00
Fuel Cell- CHP or Electric Only	$2.25
CA Manufacturer's Incentive	Unadjusted incentive x 1.2

1 Stand-alone or paired with solar PV or any otherwise eligible SGIP technology.

2 Biogas incentive is an adder that may be used in conjunction with fuel cells or any conventional CHP technologies.

Source: 2011 SGIP Handbook.

This update focuses on CHP and the factors described above that affect CHP economics for the market penetration study. The pricing is discussed in detail in later in this chapter. Each of these incentives is paid half at the time of project acceptance and half as a PBI in equal installments over five years depending on the system output. A typical PBI payment for a 3 MW CHP system is shown in **Table 2**.

Table 2: Example of PBI Payment for a 3 MW Combustion–Based CHP Using Natural Gas and Operating at an 80 Percent Capacity Factor

Year	Capacity (kW)	CF (%)	Hours/yr	kWh	Total kWh	PBI ($)	Total PBI ($)
1	3000	80	8760	21,024,000	21,024,000	87,500	87,500
2	3000	80	8760	21,024,000	42,048,000	87,500	177,000
3	3000	80	8760	21,024,000	63,069,000	87,500	262,500
4	3000	80	8760	21,024,000	84,093,000	87,500	350,000
5	3000	80	8760	21,024,000	**105,117,000**	87,500	**437,500**

Calculation: $0.50/w incentive with Tiered Incentive of 100 percent for first MW; 50 percent for second MW and 25 percent for third MW results in total of $875,000. Upfront payment of 50 percent of total, or $437,500. Remaining balance of $437,500 paid over remaining 5 years. [Note: if the CHP system operated better than 80 percent in a year, then it would receive the balance of $437,500 in a shorter amount of time; but if it operated less than 80 percent, it only gets paid for actual kWh performance.] To determine the PBI payment for each kWh over 5 years, divide the Total PBI by total kWh over 5 years = $0.004162 cents/kWh.

Source: ICF International, Inc.

Standby Rates

In the mid-1990s, the expectation was that more commercial and industrial users would use DG in the form of CHP and waste heat recovery. Several DG groups formed to promote CHP: the California Alliance for Distributed Energy Resources, the Gas Research Institute (predecessor to the Gas Technology Institute) DG Forum, the Distributed Power Coalition of America, and Electric Power Research Institute's (EPRI) Distributed Energy Resources. However, at the turn of the century, high natural gas prices and standby and other tariffs often did not recognize its costs or benefits battered CHP economics. Tariff design was particularly nettlesome to utilities, industry, and regulators alike. Much was written of the issue through the years with the following capturing the issue.

> What does it cost the electric system to provide standby service for partial-requirements customers, and how should these costs be recovered? What are the benefits of DG to the system? How should standby rates be designed to reflect these benefits and encourage customers to maximize the value of DG for themselves and the system? The decisions made today will have long-term strategic consequences.[28]

The impact of standby rates on CHP depends on their design (seasonal variation, time-of-day (TOD) cost differences, "demand ratchet," and so forth) and allocation of costs between the fixed and volumetric charge components. Both fixed and volumetric charges constitute "cost of service," but it is generally agreed that there are many ways to calculate it and that no method is correct.

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28 Johnston, Takahashi, Weston, and Murray, *Rate Structures for Customers with Onsite Generation: Practice and Innovation*, NREL/SR-560-39142. Executive Summary, page iii, December 2005.

> Recovering fixed costs in fixed charges stabilizes utility revenues, makes lenders comfortable, but puts a heavy burden on small users and discourages energy efficiency investments. Putting the bulk of cost recovery on incremental usage encourages conservation, but leaves the utility finances vulnerable to weather and other factors. … Utility pricing should reflect the strategy of the times. An emphasis on energy efficiency should flow through the organization to member customers with consistency to the extent possible.[29]

California was one of the first states to exempt CHP from standby charges.[30] This exemption was inspired by a desire to encourage greater levels of DG in light of California's electricity crisis in 2000-2001 that followed the attempted restructuring of the electric power industry. The initial exemption addressed CHP 5 MW and below and installed before December 31, 2004. These CHP resources were exempt from the demand component of standby rates for a period of 10 years from May 2011. The exemption ended June 1, 2011.

The CPUC, under statutory direction, adopted its standby rate design policies for CHP systems greater than 5 MW in 2001.[31] After this point in time, standby rate design was addressed in each utility's general rate case. However, whether the rates do in fact meet the statutory requirements for customers using distributed energy resources is not clear. The requirements are:

> (a) Those tariffs required pursuant to this section shall ensure that all net distribution costs incurred to serve each customer class, taking into account the actual costs and benefits of distributed energy resources, proportional to each customer class, as determined by the commission, are fully recovered only from that class. The commission shall require each electrical corporation, in establishing those rates, to ensure that customers with similar load profiles within a customer class will, to the extent practicable, be subject to the same utility rates, regardless of their use of distributed energy resources to serve onsite loads or over-the-fence transactions allowed under Sections 216 and 218. Customers with dedicated facilities shall remain responsible for their obligations regarding payment for those facilities.
>
> (b) The commission shall prepare and submit to the Legislature, on or before June 1, 2002, a report describing its proposed methodology for

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29 Lazar, Jim, RAP, "Challenges with Traditional Ratemaking," presentation. March 6, 2011. www.raponline.org/search/document-library/?keyword=Challenges+with+Traditional+Ratemaking&submit=Submit&publish_date_preset=&publish_date_start=&publish_date_end=&document_type_id=&sort=publish_date&order=desc.

30 Senate Bill X1 28 (Sher, Chapter 12, Statutes of 2001) (SB 28).

31 CPUC Decision 01-07-027. July, 12, 2001.

> determining the new rates and the process by which it will establish those rates.
>
> (c) In establishing the tariffs, the commission shall consider coincident peak load, and the reliability of the onsite generation, as determined by the frequency and duration of outages, so that customers with more reliable onsite generation and those that reduce peak demand pay a lower cost-based rate.[32]

And,

> (g) The commission shall adopt or maintain standby rates or charges for combined heat and power systems that are based only upon assumptions that are supported by factual data, and shall exclude any assumptions that forced outages or other reductions in electricity generation by combined heat and power systems will occur simultaneously on multiple systems, or during periods of peak electrical system demand, or both.[33]

Most recently, PG&E negotiated a settlement of most nonresidential rate design issues, including standby rate design for the next three years.[34] SCE and SDG&E may revise their standby rate design when they file their next general rate case application.

The current standby rates and their effect on the effective CHP savings rate are discussed in detail later in the pricing section.

Rule 21 Interconnection – AB 1613 Export Issues

The CPUC jurisdictional Rule 21 interconnection process was originally crafted to allow for the interconnection of distribution-level, load-serving projects. However, state energy policy has grown more aggressive in mandating the procurement of distributed energy resources that will need to interconnect to the utility's distribution system using either the Rule 21 Tariff, or the FERC jurisdiction Wholesale Access Distribution Tariff (WDAT). This class of distribution level generation projects will use programs such as the CPUC SGIP and the AB 1613 FIT for CHP.[35] These projects will be load-serving and/or exporting, the latter posing a challenge to the Rule 21 Tariff since it was designed for load-serving projects. The CPUC determined that the Rule 21 Tariff was in need of revision to allow for an increased amount of interconnection applications, and to provide interconnection for projects that will be exporting all or part of their power to the electricity system.

32 PUC Code 353.13.(a) to (c).

33 PUC Code 2841 (g).

34 PG&E 2011 GRC, Phase 2.

35 The AB 1613 FITs are described in detail in the "Electricity Prices" section later in this chapter.

On August 19, 2011, the CPUC initiated the Distribution System Interconnection Settlement (DSIS)[36] to provide a confidential forum for stakeholders to evaluate current CPUC jurisdictional interconnection rules and propose revisions to create a more transparent and expedited process. The DSIS working group met and worked through the end of 2011 and finalized the technical framework for a revised Rule 21 tariff in the first quarter of 2012. The CPUC opened Rulemaking R.11-09-011 in September 22, 2011, to consider distribution system interconnection issues. The proposed DSIS settlement will be reviewed for approval in this same proceeding. It is anticipated that the DSIS settlement agreement will provide a significantly revised Rule 21 Tariff and that any issues between stakeholders that were not resolved will be discussed in Rulemaking R.11-09-011.

Departing Load Nonbypassable Charges

A departing load charge is the portion of a utility company's electric customer's load for which the customer is still responsible to pay, even if they are no longer a customer of the utility , but still reside in that utility's service territory. An example of one of the several charges or fees that a departing customer may continue to be billed for is Nuclear Decommissioning. This charge pays for the restoration of nuclear plant sites to as near their original condition as possible once they are shut down. These charges are approved and administered by the CPUC. They are nonbypassable because the customer who chooses to meet some of its load with self-generation cannot avoid the assessment of these charges.

Nonbypassable charges consist of many components. Some are based on the funding of public purpose programs for renewable resource technologies; energy efficiency; research, development, and demonstration; self-generation; and low-income programs. Other charges include the competition transition and nuclear decommissioning charges that were added by the Electric Industry Restructuring Law.[37] Another charge arose out of the electricity crisis of 2000 and 2001 that pushed the state into power procurement to meet demand not met by the state's IOUs. Finally, the procurement costs incurred by the Department of Water Resources were passed on to the customers of the IOUs as the Department of Water Resources Bond Charge. Collectively, these charges add costs to CHP project economics and thereby influence decisions by customers to pursue CHP.

Whether departing load charges should be reduced or even eliminated continues to be debated. The charges do affect CHP economics, and some advocates argue that a reasonable

36 Previously known as the Rule 21 Working Group.

37 Electric Industry Restructuring (Assembly Bill 1890, Brulte, Chapter 854, Statutes of 1996) (AB 1890).

reduction “would be lost in the rounding in remaining bundled customer rates.[38] The High Case market scenario described in the section “Scenario Results,” located in Chapter 3, includes the market effects of eliminating these charges for customers with CHP.

AB 32 Carbon Cost Recovery – Cap-and-Trade Program

California’s three energy agencies have collaborated on the implementation of the Global Warming Solutions Act of 2006 (AB 32). With respect to cap and trade, the 2008 Joint CPUC-California Energy Commission recommendations to ARB included the following:

> We recommend that ARB treat CHP operators comparable to retail providers for the portion of CHP-generated electricity that is used on-site. To the extent that allowances are distributed to retail providers, the CHP operator should receive allowances on the same basis as retail providers and should be required to sell the received allowances through a centralized auction undertaken by ARB or its agent and use the proceeds for purposes consistent with AB 32.[39]

The ARB cap-and-trade carbon fee rules adopted October 2011 do not recognize CHP’s avoided grid GHG emissions[40] and do not provide allowances to new CHP to offset GHG emissions. The rules exact a carbon fee for carbon emitted unless the facility is “trade-exposed.” (Cost of compliance makes the facility’s products more expensive than that of its competitors.) For energy-intensive, trade-exposed facilities, free allowances are allocated for a specified number of years. In the case of CHP, substituting grid purchases with self-generated power increases the onsite GHG emissions. Consequently, the CHP owner must acquire additional allowances to cover these emissions, increasing his costs.

The CPUC proceeding on utility cost and revenues associated with GHG emissions (CPUC R.11-03-012) is not yet completed. On January 6, 2012, the joint utilities filed its revised proposal on the appropriate use of allowance auction revenues to reduce the cost burden of AB 32. One reading of the proposal is that the allowances a customer would receive as an IOU ratepayer (full requirements customer) cannot be held if a customer chooses to install CHP (partial requirements customer). Further, it is not clear if the customer who installs CHP would retain the allowance revenues associated with the remaining load served by the utility.

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38 “California Combined Heat & Power: Barriers to Entry and Public Policies for the Maintenance of Existing & the Development of New CHP.” Slides 21-22. Michael Alcantar. Presentation at the Industrial Energy Consumers of America Meeting. June 21, 2011.

39 D0810037, Order #22. Also see Findings of Fact 57, 58, and 59.

40 The cap-and-trade regulations were adopted at the ARB’s October 20, 2011, Board Meeting.

Continued Production From Existing QF/CHP

An anticipated mid-July CPUC approval of the *QF Settlement* would have led to the first utility solicitations (RFOs) in October. However, final and nonappealable CPUC approval was not achieved until November 23, 2011 (referred to as the Settlement Effective Date). Consistent with the terms of the settlement, both PG&E[41] and SCE[42] launched their CHP RFOs on December 7 and 15, 2011, respectively, and are expected to conclude in late 2012 (PG&E) and the first quarter of 2013 (SCE). SDG&E launched its RFO in early 2012. According to the terms of the settlement, each IOU will hold three CHP-only RFOs before the end of the initial program period (November 22, 2015).[43]

The scope of work under the Energy Commission contract for this market assessment anticipated the industry having some experience with the solicitations as well as with the other contract options. This was not the case, and stakeholders were reluctant to speak publicly during the development of contract offers. The surveys nonetheless did reveal some perspectives, which are listed in the sections that follow.

Plant Closures, Expansions, and Repowering

- As QF legacy PPAs near expiration, inefficient units are expected to shutdown, repower, or convert to a utility prescheduled facility (UPF)[44].
- RFO prices are determined by the prices bid. Those facilities that remain on short-run average cost (SRAC) are subject to the settlement SRAC that replaced the CPUC-adopted SRAC formula on January 1, 2012.[45] In 2015 the market heat rate replaces the transitional SRAC pricing for 2012-2014 adopted in the *QF Settlement*, and its impact is unknown at this time.
- A CHP facility currently selling to an IOU under a legacy PPA or an extension is eligible to sign a transition PPA with the same IOU when the PPA expires during the transition period. This option is considered a continuation of the PURPA mandatory purchase obligation. The facility must comply with the California Independent System Operator (California ISO) Tariff (install California ISO-approved meters and sign interconnection and other agreements) and have no change in deliveries when compared to historical deliveries. When these conditions are met, the facility can move from an expired QF

41 PG&E: December 7, 2011. See http://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/CHP/CHP.shtml.

42 SCE: December 15, 2011. See http://www.sce.com/EnergyProcurement/renewables/chp.htm.

43 Section 5.1.4, QF CHP Program Settlement Agreement Term Sheet, page 27.

44" Utility prescheduled facility" is defined in the *QF Settlement* as an existing CHP facility that has changed operations to convert to a utility controlled scheduled dispatchable generation facility, including, but not limited to, an exempt wholesale generator (EWG).

45 Section 10, CHP Program Settlement Agreement Term Sheet, dated October 8, 2010.

PPA to a transition PPA with a term up to July 1, 2015. This option is designed to give existing facilities time to bid into the CHP solicitations.

- Dispatchable option: Older CHP can be converted to a dispatchable resource for economic reasons. Some old QF contracts may have favorable terms for the customer, so underlying economics will drive decisions about which replacement PPAs to consider.

Request for Offers

- It is expected that projects operating now will continue to operate. Existing contracts have different expiration dates, so not all will terminate at the same time. The settlement has minimal affect on legacy QFs that have a one-time opportunity to execute a legacy amendment to elect an alternate energy price or pricing method, or do nothing and receive the new standard SRAC pricing. As legacy contracts near expiration, these QFs are then expected to seek a new PPA. For example, up to 20 MW QFs can choose to be a PURPA QF. Larger than 20 MW QFs can bid into a RFO, attempt to negotiate a bilateral, request an as-available PPA, if eligible, or explore other market opportunities.

The MW Target

- Meeting the MW target contained in the *QF Settlement*: At this time, there is no preconception of how the target will be met. All contract options available in the *QF Settlement* are expected to be used.
- Out-of-state QFs that sell to SCE and SDG&E: The settlement does not specifically deny these facilities from seeking a QF contract, and there is consensus among the settling parties that if they are existing facilities listed in the IOUs' July 2010 semiannual reports, then these contracts can count toward the IOU's MW target.[46]

Terms and Conditions

- There is no expectation that the settlement terms and conditions will be a sticking point for existing QFs because they were heavily negotiated in the *QF Settlement*.
- New facilities will likely have extended negotiations vs. an existing facility as there are many unknowns regarding terms and conditions that would apply to a new plant and its intended operation.
- The dispatchable requirement is problematic for facilities that operate on fixed schedules or to meet constant loads. Old PURPA facilities with a low heat rate may be more inclined to accept dispatchable terms and conditions.

46 Section 5.2.3, CHP Program Settlement Agreement Term Sheet, dated October 8, 2010.

California ISO Interconnection Process

- The costs for new California ISO metering and software are not considered expensive. However, being a participant in a cluster study could take time and be costly.
- The California ISO review process is long, and this affects the start-up of operations.

GHG Target, Cap and Trade

- The CPUC held its first GHG Rulemaking[47] workshop in early November 2011. Utilities presented proposals of how GHG auction revenues could flow back into rates. Some proposals are based on protecting cost burden by customer class, or the investment into GHG reduction mechanisms like energy efficiency and renewables. The rulemaking continues with a 24-month termination date from the September 1, 2011, date of the scoping memo. However, a proposed decision is expected in July 2012, assuming no hearings are requested.
- As a GHG reduction strategy for the electricity sector, CHP may become less attractive as a greater proportion of renewable energy is added to the mix of power on the grid. However, because of its ability to provide baseload power in institutional and industrial applications, CHP still affords greater efficiency, grid reliability benefits, and GHG reduction potential over conventional or centralized baseload power sources.

Key Drivers Affecting CHP Market – Policy, Environmental, Economic, Technical, and Terms and Conditions

- The effect of the economic and GHG policy drivers depends on whether the CHP facility is owned by the industrial host or a third party, and if the CHP facility serves an industrial host that has been identified as being at risk of leakage — for example, in the energy-intensive, trade-exposed industrial sector, as defined by the cap-and-trade regulation.

Some third-party owners of CHP facilities have steam and/or retail electricity contracts with their hosts that predate the passage of AB 32. Many of these legacy contracts do not include provisions for GHG cost recovery, and the host customer has no incentive to renegotiate the contract. Unless the ARB addresses this issue, these CHP facilities may not be able to recoup their investments because of changes in regulations. As a result, future revenues won't be enough to pay for the plant, thereby stranding the costs. Future contracts between third-party CHP providers and hosts will no doubt include provisions to address the cost of GHG emissions compliance.

- The *QF Settlement* goes only through 2020; what is needed is a long-term plan to 2050. The factors to be recognized are that grid emissions are getting cleaner; and, the benchmark market heat rate is getting better and closer to 7,000 British thermal units per kilowatt hour (Btu/kWh) compared to 8,300 Btu/kWh heat rate used in the settlement

47 Rulemaking 11-03-012. Issued March 24, 2011.

double benchmark in the initial program period. Natural gas is on the margin, and CHP is not dispatchable and is not able to compete with utility combined cycle gas turbines as a swing or marginal resource. In the future, natural gas resources are more likely to be used for regulation and load following for renewable resources. CHP may cause wind to back off at night. All these factors reduce the "degrees of freedom" for resource planners.

- Future industrial growth is either flat or negative. For the industrial sector, the market potential analysis for new CHP needs to make sense and be consistent with this growth rate. For CHP to be part of the generation mix, value must be provided as opposed to being a must-take resource. Efficient CHP that lowers overall emissions is desired, but flexibility through curtailment and dispatchability may be better than a lower emissions profile.
- GHG reductions from CHP can vary greatly depending on such things as the CHP technology and whether all power is consumed onsite or if a portion is sold to the grid. In that regard, a MW target is not always appropriate if the goal is GHG reductions. And as the grid gets cleaner with more renewables, CHP will find it harder in the future to compete with separate heat and power. For CHP, its other benefits such as deferral of transmission and distribution upgrades and congestion relief should be recognized. The effort should be to identify what needs to be achieved and make targets appropriate to that goal. Also, there is a need to reconsider certain fees and charges such as standby rates and their applicability to CHP.

Existing Combined Heat and Power Capacity Update

The project team estimates that there are 8,518 MW of operating CHP in California at 1,202 sites. The existing CHP was characterized as part of this assessment to aid in both the evaluation of the barriers to continuation of existing CHP contracts under the *QF Settlement* and the characterization of the technical market potential for new CHP deployment. An involved reconciliation process of existing CHP data was undertaken as a part of this study, to establish an accepted baseline of data on existing CHP installations in the state. Data from several California specific sources was compared to ICF's CHP Installation Database.

ICF's CHP Installation Database includes data on CHP systems throughout the country in all size ranges. The database is compiled from a variety of sources including the EIA electricity forms, the Department of Energy (DOE) Clean Energy Regional Applications Centers, Environmental Protection Agency's (EPA) CHP Partnership, utility lists, developer lists, incentive program awardees, industry publications, press releases, and other sources.

The Energy Commission provided ICF with CHP sites identified in the Quarterly Fuels Energy Report (QFER) that are more than 1 megawatt in capacity. The CPUC provided a list that contains data on all sizes of CHP systems as reported by the state's three IOUs. Each of the three major utilities also publishes a list of CHP sites they currently have power sales contracts with in their QF and Small Generator reports. These lists were all compared to the ICF CHP Installation Database, and during the reconciliation process several data corrections were found and incorporated into the ICF database. This included sites listed in other sources as retired being taken out of ICF's list, and sites that are CHP but not listed in ICF being added to the list.

Table 3 shows how the number of CHP installations and capacity in ICF's database compares to the matched capacity in the Energy Commission and CPUC lists. This table also shows some of the other sources of CHP installations in ICF's database that were not matched to systems in the Energy Commission and CPUC lists. All of the sites in ICF's database that are above 1 MW have been verified as CHP through a confirmed source (Energy Commission/CPUC lists, utility reports, EIA data, SGIP data, or various third-party sources); however, the sites under 1 MW were not individually reverified for this effort due to the limited time frame and because they do not account for a large amount of capacity. The unidentified SGIP capacity shown in the table below depicts sites that have received SGIP incentives for CHP but are not identified by name in the ICF CHP Installation Database. The SGIP program does not release information on the name of incentive recipients, and, therefore, ICF does not have each SGIP site listed by name. The SGIP sites that ICF does have by name would be accounted for in the "Other" categories in the table.

Table 3: ICF CHP Database Comparison to Energy Commission, CPUC, and Other Sources – Operating Systems

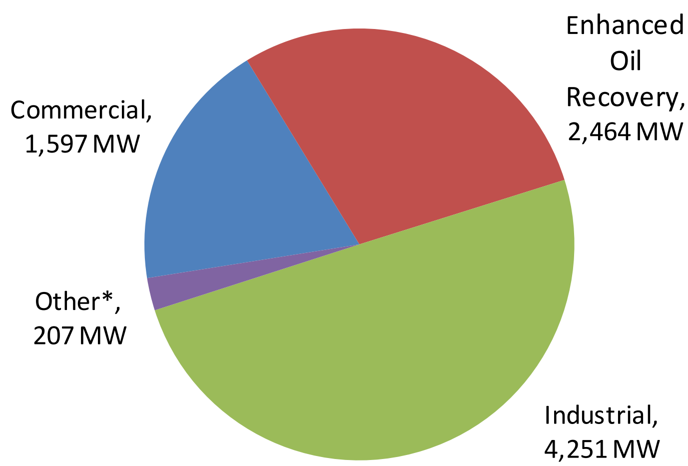
Data Source	# Sites	ICF Capacity (MW)	CEC Capacity (MW)	CPUC Capacity (MW)
Energy Commission Only	44	1,545	1,654	
Energy Commission & CPUC	131	5,726	5,944	5,694
CPUC Only	164	425		431
Utility QF/Small Gen Report	18	2		
EIA CHP	18	188		
Unidentified SGIP CHP	231	113		
Other >1 MW - Verified CHP	72	436		
Other <1 MW - Each Site not Verified	524	82		
Total	**1,202**	**8,518**	**7,598**	**6,125**

Source: ICF International.

California Existing CHP Capacity Summary

About 85 percent of the existing CHP capacity in California resides in large systems with site capacities greater than 20 MW; however, these large systems make up only 9 percent of the number of installations. As shown in **Figure 2**, the largest share of active CHP capacity is in the industrial sector, with the largest single application being the provision of steam in oil fields for enhanced oil recovery (EOR). This recovery process injects gas into the oil well to reduce the thickness of the crude oil, which increases the amount of crude oil that can be pumped from the well or oil field. **Figure 2** shows a breakdown of the existing CHP capacity in California by application class.

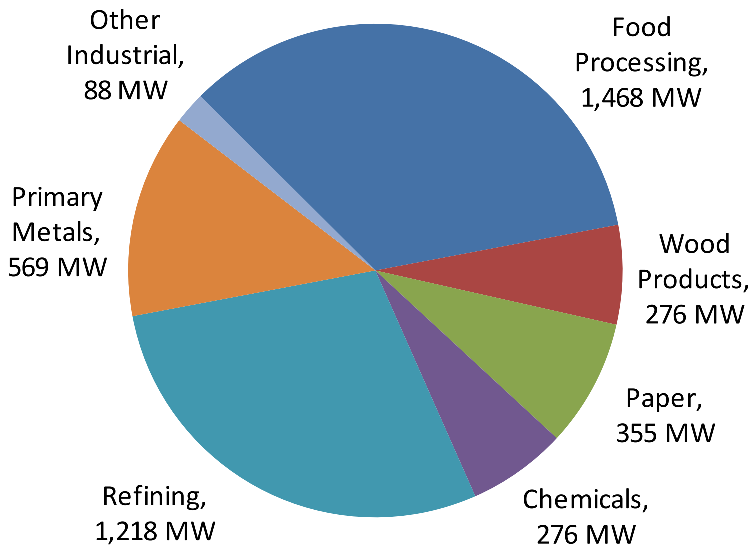
Figure 2: Existing CHP Capacity in California by Application Class



Source: ICF CHP Installation Database.

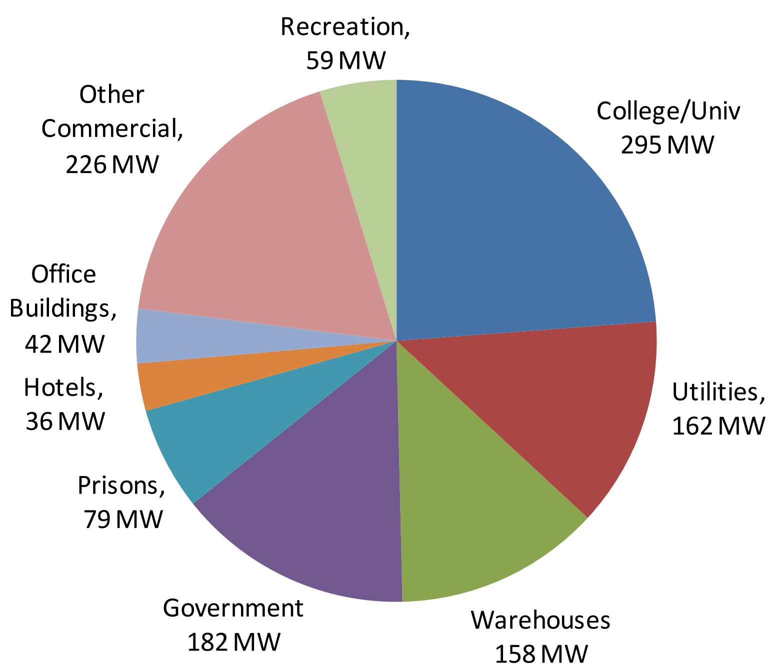
Figure 3 shows that the total capacity in the industrial sector is heavily concentrated in six process industries: food processing, refining, metals processing, pulp and paper, wood products, and chemicals. The commercial and institutional sector is spread through a larger number of individual market applications, with the largest being college/universities, water treatment, health care, and government facilities. While the commercial/institutional share is small compared to the total CHP capacity in California at 19 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 4** shows the breakdown of CHP in the commercial/institutional sector.

Figure 3: Industrial CHP Capacity in California



Source: ICF CHP Installation Database.

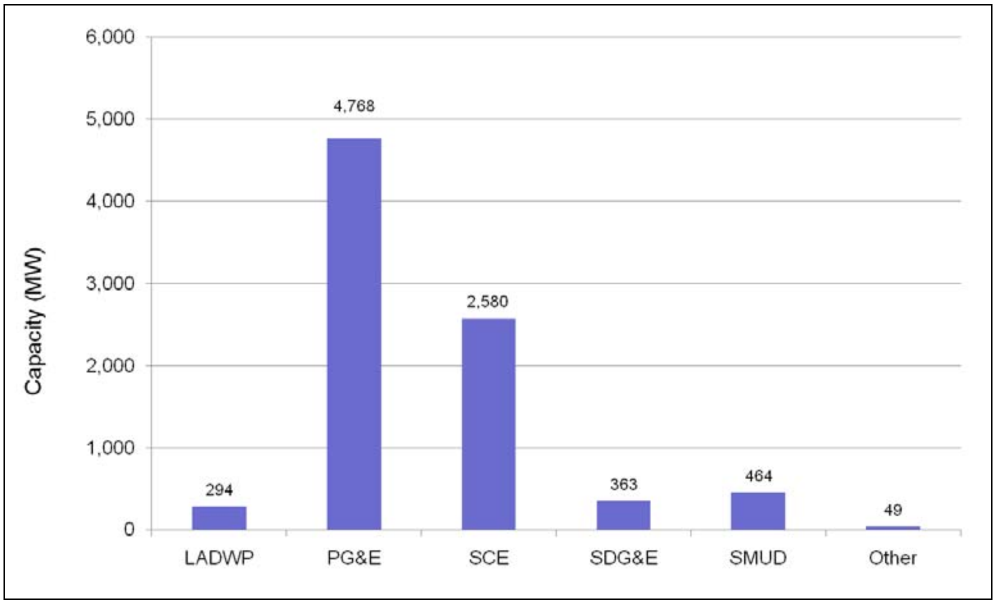
Figure 4: Commercial/Institutional CHP Capacity in California



Source: ICF CHP Installation Database.

The geographic location of CHP systems in California is spread out through all major utility territories. PG&E has the largest share of CHP capacity in its service area due to the concentration of large oil fields and refineries in its territory. **Figure 5** shows the distribution of CHP by utility service area. This breakdown depicts the actual physical location of the CHP system and does not account for systems located in one utility territory that sell electricity to other utilities or parties outside the territory. One area of the state that is known to have this issue is Kern County, where a significant amount CHP capacity (more than 500 MW) is installed at enhanced oil recovery facilities that are geographically within PG&E's service territory but export electricity to SCE.

Figure 5: Installed CHP in California by Utility Service Area

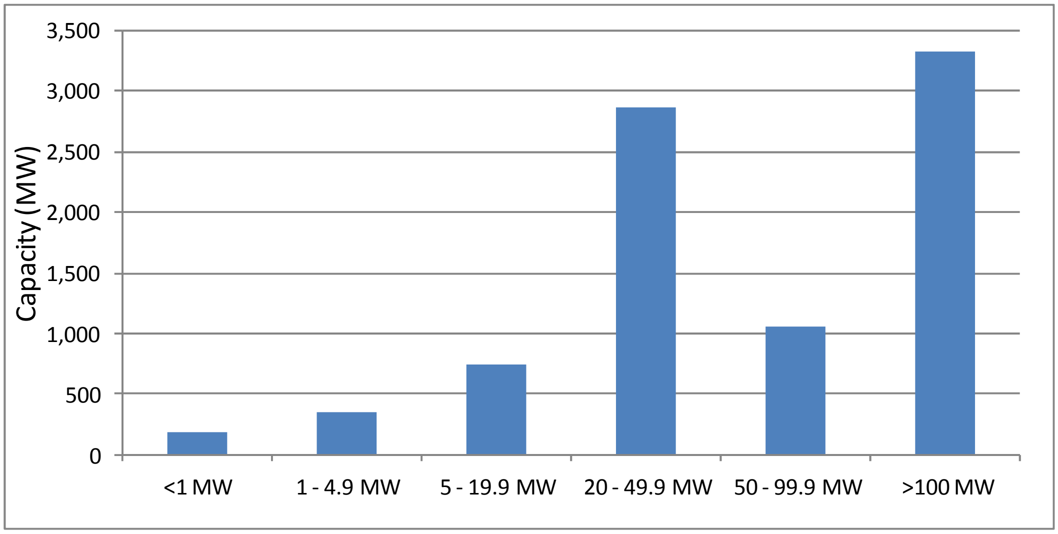


Source: CHP Installation Database.

The existing CHP installations can also be characterized in terms of the size of the facility (**Figure 6**), the primary fuel used (**Figure 7**), and the type of prime mover (**Figure 8**).

Systems smaller than 5 MW represent only 6.2 percent of total existing CHP capacity in California, while 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 composed of smaller systems. Recent growth trends in installations show that larger numbers of smaller systems have been installed in recent years. From 2006 to the present, CHP systems smaller than 5 MW have accounted for 27.7 percent of capacity growth.

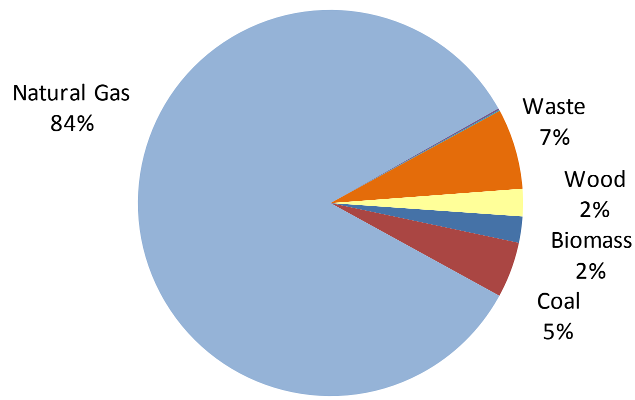
Figure 6: Existing CHP in California by Size Range



Source: ICF CHP Installation Database.

Figure 7 demonstrates that the most important fuel used for CHP in California is natural gas, which represents 84 percent of the total installed capacity. Coal and oil-fired systems are becoming increasingly rare, with only eight coal-fired CHP plants, making up 4.5 percent of capacity, and five oil-fired plants, making up less than one-tenth of 1 percent of capacity. In the last five years, no new coal or oil-fired CHP systems have been installed. Wood and biomass fuels make up 4.4 percent of the total capacity with the bulk of this capacity in the wood products, paper, and food processing industries and in wastewater treatment facilities. Waste fuels primarily from chemical and refining plants make up the remaining 6.8 percent of systems.

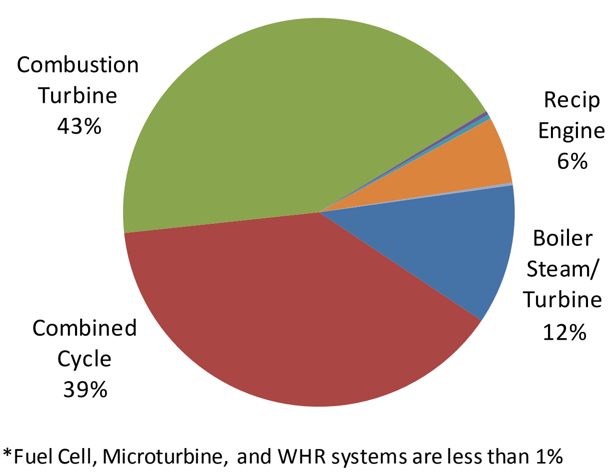
Figure 7: Existing CHP in California by Fuel



Source: ICF CHP Installation Database.

Due to the concentration of large-scale systems in the existing CHP population, prime movers accounting for the most capacity 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. The most common prime mover type in terms of number of installations is reciprocating engines; while total capacity is small (5.5 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. While the amount of capacity provided by microturbines and fuel cells remains small (5.6 percent) in the past five years, they are 34 percent of the number of systems installed.

Figure 8: Existing CHP in California by Prime Mover



Source: ICF CHP Installation Database.

California, like many parts of the country, has been hit hard with the recent economic downturn. Not only has this put a damper on new development of CHP, it has caused CHP capacity to decrease as industrial or commercial host sites have to shut down. In the past five years, there have been 314 MW of CHP in California that have ceased to operate because the host facility where they are located has shut down. National CHP development trends are starting to turn around, however, as the number of CHP systems in the development and construction stage are picking up again.

To estimate future CHP development trends, ICF maintains data on CHP systems in the proposed, planning, and construction stages of development. Since CHP systems can take multiple years to install, depending on the system size and host application, tracking systems in development can provide a picture of where the CHP market is heading. The ICF CHP Watch List shows that California currently has 11 sites representing 65.1 MW of CHP capacity that are expected to be installed during the next year. This figure represents only a portion of the capacity that is anticipated to actually enter the market because many companies do not publicize their CHP development plans. California has the sixth most CHP capacity under development in the country. Other states with large amounts of capacity in development are New York, Michigan, Washington, Wisconsin, and Virginia.

Additional detailed tables of existing CHP installations in California are shown in Appendix B.

CHP Technical Market Potential

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

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

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

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

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

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

Traditional CHP

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

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

Combined Cooling, Heating, and Power (CCHP)

All or a portion of the thermal output of a CHP system can be converted to air conditioning or refrigeration with the addition of a thermally activated cooling system. This type of system can potentially open up the benefits of CHP to facilities that do not have the year-round heating load to support a traditional CHP system. A typical CHP system in these applications would provide the annual hot water load, a portion of the space heating load in the winter months, and a portion of the cooling load during the summer months. Two subcategories were considered:

- Incremental high load factor applications: These markets represent round-the-clock commercial/institutional facilities such as hospitals, nursing homes, and hotels that could support traditional CHP but, with consideration of cooling as an output, could support additional CHP capacity while maintaining a high level of usage of the thermal energy from the CHP system.

- Low load factor applications. These represent markets such as big box retail, restaurants, and food sales that otherwise could not support traditional CHP due to a lack of thermal load.

CHP Export Market

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

Technical Potential Method

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

- Identify applications where CHP provides a reasonable fit to the electric and thermal needs of the user. Target applications are identified based on reviewing the electric and thermal energy consumption data for various building types and industrial facilities.
- Quantify the number and size distribution of target applications. Various regional data sources are used to identify the number of target application facilities by sector and by size (electric demand) that meet the thermal and electric load requirements for CHP.
- Estimate CHP potential in terms of 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 potential.

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 used 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.

To identify applications where CHP provides a reasonable fit to the electric and thermal needs of the user, this study reviewed electric and thermal energy (heating and cooling) consumption data for various building types and industrial facilities. Data sources included the DOE EIA *Commercial Buildings Energy Consumption Survey (CBECS),* the DOE *Manufacturing Energy Consumption Survey (MECS),* the *Major Industrial Plant Database (MIPD*), and *Commercial Energy Profile Database (CEPD*)[48], and various market summaries developed by DOE, Gas Technology Institute (GTI), and the American Gas Association. Existing CHP installations in the commercial/institutional and industrial sectors were also reviewed to understand the required profile for CHP applications and to identify target applications.

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

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

- Traditional CHP – Size the CHP system for the base thermal load (domestic hot water, pool heating, showers, laundries, and kitchens), which usually results in a system sized below the base electric load for commercial facilities. For many industrial facilities, the CHP system is sized to the process steam or hot water load but may be capped by the electric demand at the site (for example, thermal demand could support a larger CHP system).
- 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

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

a larger CHP system that better matches the electric demand in certain commercial and institutional applications.

- Export CHP – Size the CHP system to meet the entire thermal load at an industrial facility, with excess electricity generation being exported to the grid. The previous two categories are based on the assumption that all of the thermal and electric energy is used on-site. Within large industrial process facilities, there is often excess steam demand that could support larger CHP systems with significant quantities of electricity that could be exported to the wholesale power system.

Table 4 and **Table 5** show the CHP market applications classified by these categories as well as their assumed load profiles. Applications with a high load factor were assumed to operate for 7,500 hours a year, whereas applications with a low load factor were assumed to operate for 5,000 hours a year. The category and load profile combinations make up the four markets that were defined at the beginning of this section. Each application is shown with both the corresponding North American Industry Classification System (NAICS) code and Standard Industrial Classification (SIC) code.

Table 4: Traditional CHP Target Applications

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

Source: ICF International.

Table 5: Combined Cooling Heating and Power Target Applications

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

Source: ICF International.

California Target CHP Facilities

Various commercial and industrial facility databases were used to identify the number of target application facilities in California by sector and by size (electric demand) that meet the thermal and electric load requirements for CHP. The primary data source to identify potential targets for CHP installations in California was the Dun & Bradstreet (D&B) *Hoovers* Database. The D&B *Hoovers* Database was acquired in October 2011, contains information on the majority of businesses throughout the country, and can be sorted to provide a listing of industrial and commercial facilities in a specific region. This analysis used a set of data consisting of facilities in California that have more than five employees and are in the target applications specified above. The site data includes information on:

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

Almost 50,000 sites from the D&B *Hoovers* database, including 14,630 industrial[49] sites and 35,310 commercial sites, were screened for CHP potential in this study. Industrial facilities from other sources were also used to supplement the D&B *Hoovers* list in the large industrial market segment. Special attention was paid to the large refineries to make sure that the estimates for additional CHP potential were consistent with current refining industry assumptions. In the *ICF 2009 CHP Market Assessment for California,*[50] a list of the major refineries in California was compiled, along with detailed information on their electric demand and process steam flows. This was used to independently calculate the remaining potential for CHP in the refining sector. This same data was used in this study to characterize the refining sector. The large industrial plants in the combined list were also independently checked to corroborate the electric and boiler fuel data and the estimated values calculated through the method detailed below.

Quantify Electric and Thermal Loads for CHP Target Applications

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

Electric Load Estimation

It was assumed that the CHP systems would be sized to meet the base thermal loads (heating and cooling) of a site unless the CHP system sizing exceeded the average facility electric demand. In this case, industrial sites are assumed to export excess electricity to the grid, whereas commercial sites would limit the system size to the site's average electric demand. Total annual kilowatt hour (kWh) electricity load is estimated for each site using algorithms in the CHP Market Model based on such characteristics as number of employees, annual sales or facility square footage. The average electric demand of each facility in the dataset was estimated by dividing the total kWh electricity load by the typical operating hours corresponding with the application's load factor (7,000 hours a year for high load factor, 5,000 hours a year for low load factor).

Of the 50,000 facilities in California that were screened for CHP potential, close to half were dropped from the analysis due to the lack of estimated electric demand that would lead to viable CHP economics. This assessment required a minimum electric demand of 50 kilowatt (kW) for a site to be included in the technical potential. After screening for this minimum electric demand, only about 25,000 sites remained as potential CHP candidates.

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49 All of the sites from the D&B *Hoovers* database were categorized into their respective market applications based on the primary NAICS code listed in the database. Many facilities have a variety of process types and therefore have several secondary NAICS codes associated with them, however the primary NAICS code of the facility was used for classification in this report.

50 California Energy Commission, Public Interest Energy Research Program. *Combined Heat and Power Market Assessment*. Prepared by ICF International, Inc., CEC-500-2009-094-F, April 2010.

Thermal Load Estimation

As described earlier, this assessment assumes that the CHP systems would be sized to meet the base thermal loads (heating and cooling) of each site. Estimation of the thermal load is important to properly size the CHP system for high thermal usage and to determine whether the thermal load would limit the CHP system size. As stated previously, information on thermal load for the target CHP applications was derived from data in DOE's *CBECS, MECS*, the *MIPD*, and *CEPD*, as well as studies of industrial electric and thermal profiles developed by DOE, GTI, and the American Gas Association. To refine the thermal demand estimates for the commercial sector, the *CEUS* was used to make the thermal demand estimates be more indicative of a California climate. These data sources provided sufficient information on the end-use energy consumption in commercial and industrial facilities such that average power-to-heat ratio factors for each target application could be developed.

A change in the method compared to ICF's 2009 assessment of CHP potential in California,[51] is the application of power-to-heat (P/H) ratios for industrial facilities at the six-digit NAICS level rather than at the two-digit SIC level. This difference means that the electric and thermal loads were applied at a much more detailed level for the line of business of each facility. For example, instead of having one P/H ratio for all of the food processing sector, now ICF has applied detailed factors to all of the subsectors, such as poultry processing, grain processing, fluid milk manufacturing, vegetable and fruit canning, and so forth. This detailed electric and thermal data was used to develop size-specific thermal factors for each CHP target application that are used to estimate the CHP system size as a function of average electric demand. The thermal factor is based on both the P/H ratio of the application as well as the P/H ratio of a typical CHP system for that application.

CHP System Sizing

The electric and thermal data described above were used to develop thermal factors for each application that is used to estimate the CHP system size for each potential site as a function of average electric demand. The thermal factor is based on both the power-to-heat ratio (P/H) of the application as well as the P/H ratio of a typical CHP system for that application. The thermal factor is multiplied by the average electric demand to determine the estimated CHP system size for each site. A thermal factor of one would result in the CHP system capacity being equal to the average electric demand of the facility. A thermal factor less than one would indicate that the application is thermally limited and the resulting CHP system size would be below the average electric demand of the facility. A thermal factor greater than one indicates that a CHP system sized to the thermal load would produce more electricity than can be used on-site, resulting in excess power that could be exported to the grid. 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.

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51 California Energy Commission, Public Interest Energy Research Program. *Combined Heat and Power Market Assessment*. Prepared by ICF International, Inc., CEC-500-2009-094-F, April 2010.

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

Technical Potential Results

Estimates for CHP technical market potential were developed using the method described above for both existing facilities in 2011 and new facility growth between 2011 and 2030. This section profiles the CHP technical potential estimates by application and size range for the entire state and for each utility region. The estimates are divided into the CHP technical potential that serves on-site electric demands at target facilities and additional CHP technical potential that is available if the facilities are allowed to export electricity to the grid (export capacity). Accordingly, the "on-site" tables do not include any CHP capacity that is over the facility average electric demand. Excess CHP capacity that is available in certain applications is presented in the export tables.

The total technical market potential (on-site and export) for CHP equals 14,293 MW in 2011 for potential at existing commercial and industrial facilities with another 1,671 MW expected from new or expanded commercial and industrial facilities during the forecast period, for a total of almost 16,000 MW in 2030.

Technical Potential—2011

Table 6 shows the breakdown of onsite CHP technical potential by utility region. The two regions with the largest amount of technical potential are PG&E and SCE. This is primarily due to the large geographic areas covered by these two utilities. 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. 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 6: On-Site CHP Technical Potential (MW) by Utility Region in 2011

Utility Region	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW	Total
LADWP	229	189	299	197	179	1,093
PG&E	1,033	435	998	591	297	3,354
SCE	1,040	385	942	604	289	3,259
SDG&E	220	105	212	109	46	692
SMUD	81	43	98	84	21	328
Other North	57	23	45	72	0	196
Other South	106	41	99	90	0	336
Total (MW)	**2,765**	**1,221**	**2,693**	**1,747**	**833**	**9,259**

Source: ICF International.

Table 7, **Table 8**, **Table 9**, **Table 10**, and **Table 11** summarize the current (2011) technical potential estimates by application, size, and utility territory. The technical potential for CHP is highest in industrial sectors that currently have a large number of existing CHP installations, such as chemicals, food processing, and paper production. However, because many of the very large industrial facilities in California already have CHP systems, the majority of the potential now falls in the mid-range system sizes between 1 MW and 20 MW.

Commercial facility CHP potential is heavily concentrated in the size ranges below 5 MW, where about 75 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 7: On-Site CHP Technical Potential at Existing Industrial Facilities in 2011

NAICS	Application	50-500 kW (MW)	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total (MW)
311	Food	226	109	258	196	56	845
313	Textiles	45	10	30	8	26	119
321	Lumber and Wood	56	17	45	23	25	165
337	Furniture	0	0	0	0	0	0
322	Paper	61	54	168	132	20	434
323	Printing	0	0	3	0	0	3
325	Chemicals	149	99	396	360	97	1,100
324	Petroleum Refining	11	30	62	58	125	285
326	Rubber/Misc Plastics	44	18	17	6	0	86
327	Stone/Clay/Glass	12	12	23	0	0	47
331	Primary Metals	28	5	13	9	0	55
332	Fabricated Metals	14	3	1	0	0	18
333	Machinery/Computer Equip	10	5	10	0	0	25
336	Transportation Equip.	18	13	15	26	0	73
335	Instruments	13	1	3	0	37	53
339	Misc. Manufacturing	0	0	0	0	0	0
	Total (MW)	**688**	**375**	**1,042**	**818**	**385**	**3,309**

Source: ICF International.

Table 8: On-Site CHP Technical Potential at Existing Commercial Facilities in 2011

NAICS	Application	50-500 kW (MW)	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total (MW)
491	Post Offices	7	2	0	0	0	9
452	Retail	245	36	15	0	0	296
493	Refrigerated Warehouses	16	6	4	5	0	31
48811	Airports	1	2	8	29	27	67
2213	Water Treatment	28	7	7	0	0	41
445	Food Stores	220	8	8	0	0	235
722	Restaurants	163	9	7	9	0	187
531	Commercial Buildings	294	368	511	0	0	1,172
531	Multifamily Buildings	105	111	72	0	0	288
721	Hotels	166	76	158	38	0	439
8123	Laundries	25	4	2	0	0	31
518	Data Centers	19	6	7	0	0	32
8111	Car Washes	18	1	0	0	0	18
512131	Movie Theaters	1	0	1	0	0	2
71394	Health Clubs	55	6	3	0	0	63
71391	Golf/Country Clubs	63	1	2	0	0	66
623	Nursing Homes	128	4	14	0	0	146
622	Hospitals	54	56	267	58	0	435
6111	Schools	216	23	32	9	0	280
6113	College/Univ.	50	24	229	649	396	1,348
612	Museums	9	1	0	0	0	11
91	Government Buildings	182	92	268	131	25	698
92214	Prisons	12	5	35	0	0	52
	Total (MW)	**2,077**	**846**	**1,650**	**929**	**447**	**5,950**

Source: ICF International.

The estimate of the CHP export market is based primarily on the excess power capacity at the largest 100 industrial facilities in the state, characterized in terms of steam demand. Most of this potential comes from a handful of very large refineries, chemical plants, and food processors. The estimate of technical potential for additional export CHP capacity in enhanced oil recovery applications is based on a 1999 EPRI analysis of the potential at 10 existing oil fields and the degree of market saturation that already exists for CHP.[52] These estimates were increased by 26 percent to reflect increasing levels of EOR steam injection as

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

reported in the 2000 through 2010 annual reports from the Division of Oil, Gas and Geothermal Resources (Department of Conservation).

There is a total technical CHP export potential of 5,034 MW. Export potential is geographically located in this study for placement in utility service territories; however, facilities that export power have the freedom to sell their electricity to any entity they wish, including those outside their geographic area.

Table 9: Export CHP Technical Potential at Existing Industrial Facilities in 2011

NAICS	Application	50-500 kW (MW)	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total (MW)
211	Enhanced Oil Recovery	0	0	0	0	1,350	1,350
311	Food	0	0	91	97	297	486
313	Textiles	0	0	0	9	4	12
321	Lumber and Wood	0	0	38	31	106	175
337	Furniture	0	0	0	0	0	0
322	Paper	0	0	24	329	601	955
323	Printing	0	0	0	10	0	10
325	Chemicals	0	0	89	267	543	899
324	Petroleum Refining	0	0	43	95	946	1,084
326	Rubber/Misc Plastics	0	0	0	12	0	12
327	Stone/Clay/Glass	0	0	0	0	0	0
331	Primary Metals	0	0	0	8	0	8
332	Fabricated Metals	0	0	0	10	0	10
333	Machinery/Computer Equip	0	0	0	0	0	0
336	Transportation Equip.	0	0	0	27	0	27
335	Instruments	0	0	0	5	0	5
339	Misc. Manufacturing	0	0	0	0	0	0
	Total (MW)	**0**	**0**	**286**	**901**	**3,847**	**5,034**

Source: ICF International.

Table 10 summarizes the export technical potential by utility area. The utility with the largest amount of export CHP technical potential is PG&E due to the large presence of EOR opportunities in the PG&E service territory.

Table 10: Export CHP Technical Potential – in 2011 by Utility Territory

Utility Region	50-500 kW (MW)	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total (MW)
LADWP	0	0	5	34	240	279
PG&E	0	0	126	322	2,640	3,088
SCE	0	0	105	433	691	1,229
SDG&E	0	0	10	25	171	206
SMUD	0	0	5	32	0	37
Other North	0	0	19	13	106	138
Other South	0	0	16	42	0	58
Total (MW)	**0**	**0**	**286**	**901**	**3,847**	**5,034**

Source: ICF International.

The total technical potential for CHP in California for 2011 is summarized by CHP market sector in **Table 11**. It indicates that there is more remaining potential in commercial facilities than in industrial facilities, which is a departure from the traditional characterization of CHP target markets. There is also a heavy concentration of potential in the small-size ranges, indicating that many large facilities already have CHP systems for their on-site needs, leaving the remaining large-size CHP potential in the export market.

Table 11: Total CHP Technical Potential at Existing Facilities – Commercial and Industrial – in 2011 by CHP 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 On-site	688	375	1,042	818	385	3,309
Commercial - Traditional	200	23	49	0	0	272
Commercial - Heating & Cooling	1,773	712	1,529	929	447	5,390
Residential - Heating & Cooling	105	111	72	0	0	288
Export Existing	0	0	286	901	3,847	5,034
Total (MW)	**2,765**	**1,221**	**2,978**	**2,648**	**4,679**	**14,293**

Source: ICF International.

In addition to the technical potential figures estimated through ICF's standard method, the impact of a high electric focus by IOUs was also calculated to measure the increase in potential that could be achieved if electric utilities owned large CHP systems and designed them to maximize power production. In the standard method, large industrial sites with high electric and thermal loads have their CHP technical potential estimated assuming they would install a simple cycle gas turbine. With a high electric focus, it is assumed these large industrial sites with technical potential greater than 50 MW would alternatively install combined cycle systems, which have higher power-to-heat ratios, and would yield higher amounts of electricity output. **Table 12** shows the increased export capacity that is available assuming combined cycle systems would be installed at sites with high amounts of technical potential.

Table 12: Export CHP Technical Potential – High Electric Focus by IOUs

Utility Region	50-500 kW (MW)	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total (MW)
LADWP	0	0	5	34	592	631
PG&E	0	0	126	322	2,876	3,323
SCE	0	0	105	433	1,425	1,963
SDG&E	0	0	10	25	330	365
SMUD	0	0	5	32	0	37
Other North	0	0	19	13	195	228
Other South	0	0	16	42	0	58
Total (MW)	**0**	**0**	**286**	**901**	**5,419**	**6,606**

Source: ICF International.

Technical Potential Growth Between 2011 and 2030

While the 2011 technical potential estimate is based on the facility data in the potential CHP site list, the 2030 estimate includes economic growth projections for target applications between 2011 and 2030. To estimate the development of new commercial and industrial facilities and expansion in existing facilities between the present and 2030, economic projections for growth by target market applications in California were reviewed. The growth factors used in the analysis for growth between 2011 and 2030 by individual sector are shown in **Table 13** and **Table 14**. These growth projections are from the EIA's *Annual Energy Outlook (AEO) 2011* Reference Case, which reflects expected growth rates by industry application through 2030. The growth rates were used in this analysis as an estimate of the growth in new facilities or expansion at existing facilities. In cases where an economic sector is declining, it was assumed that no new facilities or expanded capacity at existing facilities would be added to the technical potential for CHP.

Table 13: Industrial Application Growth Projections

Application	2011-2030 Growth Rate, %
Food	18.98%
Textiles	0.00%
Lumber and Wood	11.10%
Furniture	11.10%
Paper	6.07%
Publishing	0.00%
Chemicals	0.00%
Petroleum Refining	0.00%
Rubber / Misc Plastics	0.00%
Stone/Clay/Glass	0.00%
Primary Metals	0.00%
Fabricated Metals	13.48%
Machinery/Computer Equip.	13.48%
Transportation Equip.	13.48%
Instruments	13.48%
Misc. Manufacturing	10.09%

Source: EIA 2011 Annual Energy Outlook, Reference Case.

Table 14: Commercial Application Growth Projections

Application	2011-2030 Growth Rate, %
Post Offices	12.11%
Big Box Retail	28.10%
Warehouses	15.91%
Airport Facilities	26.79%
Wastewater Treatment/Sanitary	24.23%
Food Stores	21.43%
Restaurants	20.00%
Commercial Office Buildings	24.23%
Apartments	11.10%
Hotels	26.79%
Laundries	26.79%
Data Centers	24.23%
Car Washes	24.23%
Movie Theaters	28.10%
Health Clubs	24.23%
Golf/Country Clubs	26.79%
Nursing Homes	30.61%
Hospitals	30.61%
Schools	12.77%
Colleges/Universities	12.77%
Museums	14.81%
Government Buildings	24.23%
Prisons	26.79%

Source: EIA 2011 Annual Energy Outlook, Reference Case.

Table 15 and **Table 16** show the additional CHP technical market potential due to projected economic growth in California over the period of the analysis.

Table 15: Total CHP Technical Potential Growth Between 2011 and 2030 by CHP 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 On-site	60	29	68	51	20	228
Commercial - Traditional	51	6	13	0	0	70
Commercial - Heating & Cooling	408	173	363	154	64	1,162
Residential - Heating & Cooling	12	12	8	0	0	32
Export Existing	0	0	9	40	131	180
Total (MW)	**531**	**220**	**461**	**245**	**214**	**1,671**

Source: ICF International.

Table 16: CHP Technical Potential Growth Between 2011 and 2030 by Utility Territory

Utility Region	50-500 kW (MW)	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total (MW)
LADWP	50	39	62	28	37	216
PG&E	203	84	184	84	96	651
SCE	187	59	135	65	56	502
SDG&E	44	18	40	19	3	125
SMUD	17	8	18	22	3	67
Other North	11	4	8	13	19	56
Other South	19	6	14	15	0	54
Total (MW)	**531**	**220**	**461**	**245**	**214**	**1,671**

Source: ICF International.

The total technical potential for CHP in 2030 is the summation of the 2011 technical potential and the growth in CHP potential between 2011 and 2030. **Table 17** through **Table** 20 summarize the total technical potential for CHP in 2030.

Table 17: Total Industrial CHP Technical Potential in 2030

NAICS	Application	50-500 kW (MW)	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total (MW)
311	Food	269	129	307	233	67	1,005
313	Textiles	45	10	30	8	26	119
321	Lumber and Wood	62	19	50	25	28	184
337	Furniture	0	0	0	0	0	0
322	Paper	65	57	178	140	21	461
323	Printing	0	0	3	0	0	3
325	Chemicals	149	99	396	360	97	1,100
324	Petroleum Refining	11	30	62	58	125	285
326	Rubber/Misc Plastics	44	18	17	6	0	86
327	Stone/Clay/Glass	12	12	23	0	0	47
331	Primary Metals	28	5	13	9	0	55
332	Fabricated Metals	16	3	1	0	0	20
333	Machinery/Computer Equip.	12	6	11	0	0	29
336	Transportation Equip.	21	15	18	30	0	83
335	Instruments	14	1	3	0	41	60
339	Misc. Manufacturing	0	0	0	0	0	0
	Total (MW)	**748**	**404**	**1,110**	**869**	**405**	**3,537**

Source: ICF International.

Table 18: Total Commercial CHP Technical Potential in 2030

NAICS	Application	50-500 kW (MW)	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total (MW)
491	Post Offices	8	2	0	0	0	10
452	Retail	314	46	19	0	0	379
493	Refrigerated Warehouses	19	7	5	6	0	36
48811	Airports	1	2	10	37	34	85
2213	Water Treatment	35	9	9	0	0	52
445	Food Stores	267	10	10	0	0	286
722	Restaurants	196	11	8	11	0	225
531	Commercial Buildings	365	457	635	0	0	1,457
531	Multifamily Buildings	117	123	80	0	0	320
721	Hotels	210	96	200	48	0	556
8123	Laundries	32	5	3	0	0	39
518	Data Centers	24	7	9	0	0	40
8111	Car Washes	22	1	0	0	0	23
512131	Movie Theaters	1	0	1	0	0	3
71394	Health Clubs	68	7	4	0	0	79
71391	Golf/Country Clubs	80	1	3	0	0	84
623	Nursing Homes	167	5	18	0	0	191
622	Hospitals	70	73	349	76	0	568
6111	Schools	244	26	36	10	0	316
6113	College/Univ.	56	27	258	732	447	1,520
612	Museums	10	1	0	0	0	12
91	Government Buildings	226	114	333	163	31	867
92214	Prisons	15	6	44	0	0	66
	Total (MW)	**2,548**	**1,039**	**2,034**	**1,082**	**512**	**7,214**

Source: ICF International.

Table 19: Total Export CHP Technical Potential in 2030

NAICS	Application	50-500 kW (MW)	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total (MW)
211	Enhanced Oil Recovery	0	0	0	0	1,350	1,350
311	Food	0	0	106	103	370	579
313	Textiles	0	0	0	9	4	12
321	Lumber and Wood	0	0	39	35	120	195
337	Furniture	0	0	0	0	0	0
322	Paper	0	0	24	351	645	1,020
323	Printing	0	0	0	10	0	10
325	Chemicals	0	0	89	267	543	899
324	Petroleum Refining	0	0	43	95	946	1,084
326	Rubber/Misc Plastics	0	0	0	12	0	12
327	Stone/Clay/Glass	0	0	0	0	0	0
331	Primary Metals	0	0	0	8	0	8
332	Fabricated Metals	0	0	0	12	0	12
333	Machinery/Computer Equip	0	0	0	0	0	0
336	Transportation Equip.	0	0	0	32	0	32
335	Instruments	0	0	0	6	0	6
339	Misc. Manufacturing	0	0	0	0	0	0
	Total (MW)	**0**	**0**	**302**	**939**	**3,978**	**5,219**

Source: ICF International.

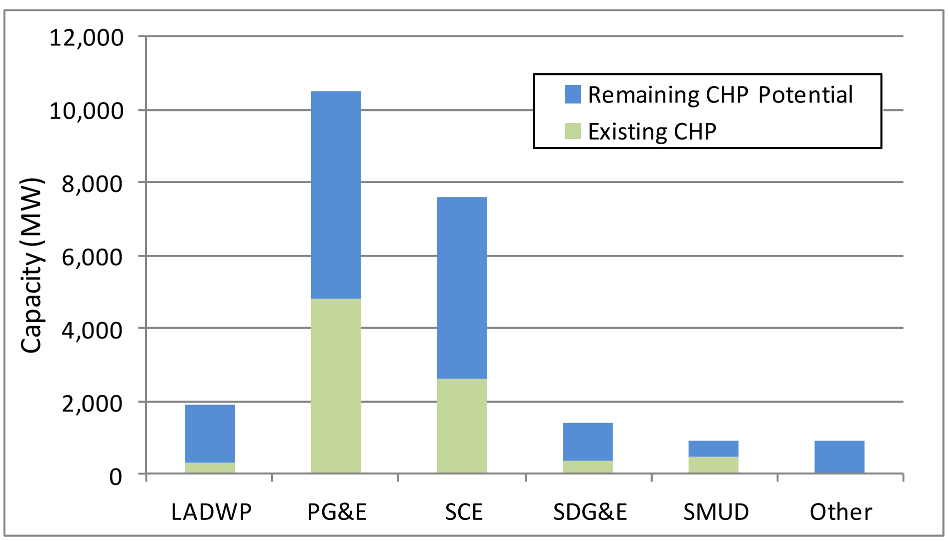
Table 20: Total CHP Technical Potential in 2030 by Utility Territory

Utility Region	50-500 kW (MW)	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total (MW)
LADWP	278	228	355	253	473	1,588
PG&E	1,234	518	1,193	943	3,203	7,090
SCE	1,227	441	1,013	1,074	1,236	4,991
SDG&E	265	123	251	152	234	1,024
SMUD	98	51	105	153	24	432
Other North	68	26	68	78	149	390
Other South	125	47	114	163	0	449
Total (MW)	**3,295**	**1,434**	**3,099**	**2,815**	**5,320**	**15,964**

Source: ICF International.

Figure 9 profiles existing CHP capacity and remaining CHP potential (through 2030) by utility service area. The most significant regions for growth are in the PG&E and SCE service territories. However, both LADWP and SDG&E show that they have significant room for growth in CHP capacity.

Figure 9: Existing CHP and Total Remaining CHP Potential by Utility Territory



Source: ICF International.

The CHP Market Model will use this technical potential data to estimate forecasted CHP market penetration between 2011 and 2030. Detailed tables describing the technical potential by utility region are provided in Appendix C.

Natural Gas and Electricity Pricing

The relationship between natural gas and electric retail prices is a major determinant of the competitiveness of CHP. This section describes the current gas and electric prices and the 20-year forecast for these prices assumed for the CHP market analysis, and compares the 2011 price assumptions to the 2009 assumptions.

Natural Gas Prices

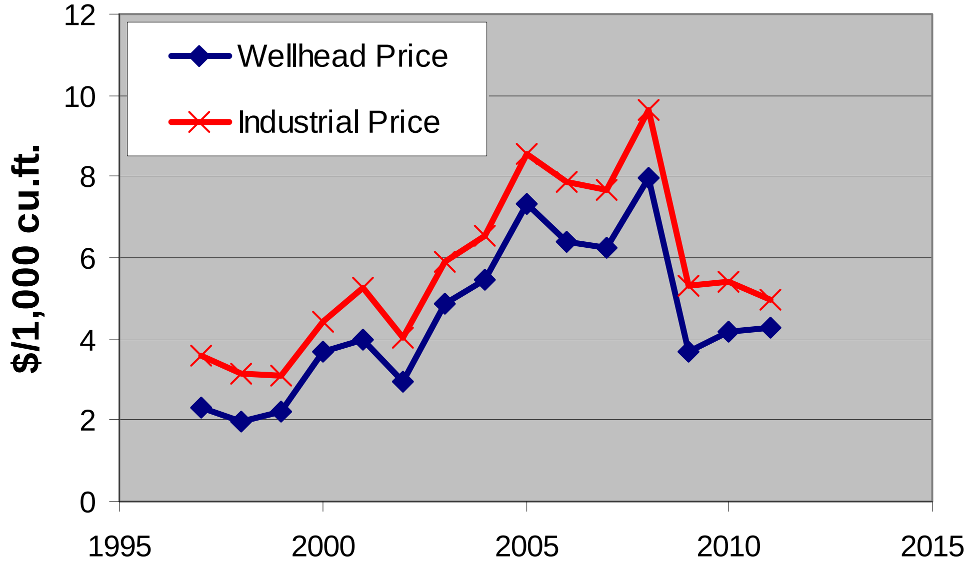
Natural gas prices depend on the cost of gas at the wellhead and the cost of transportation to the customer. This section briefly describes the natural gas market trends, the long-range wellhead price forecast, and the transportation markups within California that make up the customer retail price.

Natural Gas Market Trends and Outlook

The natural gas market of today is much different from just a few years ago. Prices have declined significantly from a period of high prices and volatility that began in 2000 and lasted until 2008, as shown in **Figure 10**.

The lower prices following the 2008 price spike can be explained by two factors: a short-term reduction in demand caused by the recession and a long-term change in the resource outlook for natural gas supply. While the long-term demand outlook for natural gas is increasing, it is increasing at a fairly slow rate with these increases primarily in electricity generation. The biggest factor that is expected to keep natural gas prices lower in the future is the increase in production from unconventional sources — particularly shale gas. Since 2005, shale gas production has been increasing at about 50 percent per year. These improved production techniques have about doubled the North American natural gas resource that can be produced for under $5/MMBtu. At current rates of production and consumption, the North American gas resource will last for 150 years.

Figure 10: Average U.S. Wellhead and Industrial Natural Gas Prices, 1997 – 2011



Source: U.S. Energy Information Administration.

This radically different resource outlook is reversing the future trends predicted in past forecasts, which had foreign supplies outcompeting increasingly expensive domestic supplies on price and being imported to the United States as liquefied natural gas (LNG).

These changes have lowered the long-term marginal cost for natural gas production and increased the resource base. Earlier long-term forecasts, before the dramatic increase in economic production of shale gas became evident, were based on a much lower resource base. Marginal supplies in later years were expected to come from much more expensive LNG. Today, prominent natural gas market forecasts (EIA, Energy Commission, and ICF) predict much lower gas prices and lower volatility due to the large increase in economically producible reserves that effectively removes LNG as the long-term marginal source of supply.

Wellhead Price Forecast

Two long-range forecasts were compared for use in this analysis:

- The *2011 Natural Gas Market: Outlook* series of reports, workshops, and scenario outputs in preparation by the Energy Commission.[53]
- The U.S. Energy Information Administration *Annual Energy Outlook for 2011*.[54]

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53 Brathwaite, Leon D., Paul Deaver, Robert Kennedy, Ross Miller, Peter Puglia, William Wood. 2011. *2011 Natural Gas Market Assessment: Outlook*. California Energy Commission, Electricity Supply Analysis Division. Publication Number: CEC-200-2011-012-SD.

The 2011 Energy Commission reference forecast is shown in **Figure 11**. The average real rate of growth in prices over the forecast period is about 2.6 percent per year. Citygate hub prices are lowest in the northern half of the state represented by PG&E. Citygate hub prices are higher for the southern part of the state with SCE being about $0.30/MMBtu higher than PG&E and SDG&E about $0.60 higher. The Malin Hub serving the northern half of the state, not shown on the figure, is about $0.10/MMBtu cheaper than the Henry Hub price. The Needles Hub serving the southern half of the state is about $0.20/MMBtu higher than the Henry Hub price.

Figure 12 shows the comparison between the *EIA 2011 Annual Energy Outlook* (EIA *AEO 2011)* Reference Case Henry Hub gas price forecast and the Energy Commission Reference Case. The EIA gas price forecast begins lower than the Energy Commission forecast but grows faster during the forecast period.

For the CHP market analysis, the EIA natural gas price track was chosen as the basis for estimating changes in commodity gas prices over time. Intrastate rate differentials were based on the Energy Commission forecast. PG&E is assumed to receive gas at the California border at a $0.10/MMBtu discount to the Henry Hub price. SCE and SDG&E are assumed to receive gas at the California border at a $0.20/MMBtu markup to the Henry Hub price.

The Energy Commission forecast contains important information on price differences within the state and is part of a public review and comment process that should ensure compatibility with California issues and trends. The EIA forecast is integrated with a forecast of electric prices. This integration is important in correctly tracking the long-term relationship between natural gas prices and electricity generation prices.

The natural gas wellhead price forecasts analyzed and use for this study were the most current available at the time the work was conducted. Some forecasts that came out during the final report editing show that the long-term outlook for gas prices continues to be reduced. The EIA preliminary *2012 Annual Energy Outlook* (*AEO 2012*) was released on January 23, 2012, shows Henry Hub prices that are 10-20 percent lower than the 2011 Reference Case through 2015 and 2-4 percent lower from 2020-2030.[55] Bentek Energy is forecasting sharp price reductions in the near term due to the continued boom in shale gas production, mild weather, and full storage fields.[56]

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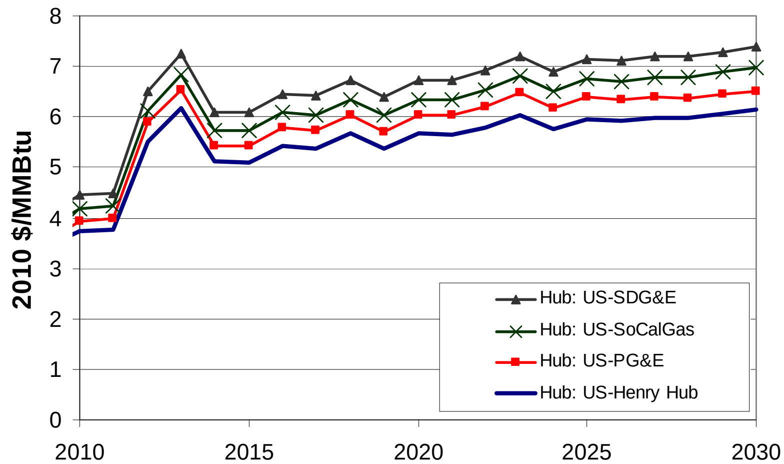
54 *Annual Energy Outlook 2011 with Projections to 2035*, U.S. Energy Information Administration, DOE/EIA-0383(2011), April 2011. http://www.eia.gov/forecasts/aeo/.

55 *AEO 2012* Early Release Overview, EIA website, posted January 23, 2012. http://205.254.135.7/forecasts/aeo/er/early_prices.cfm.

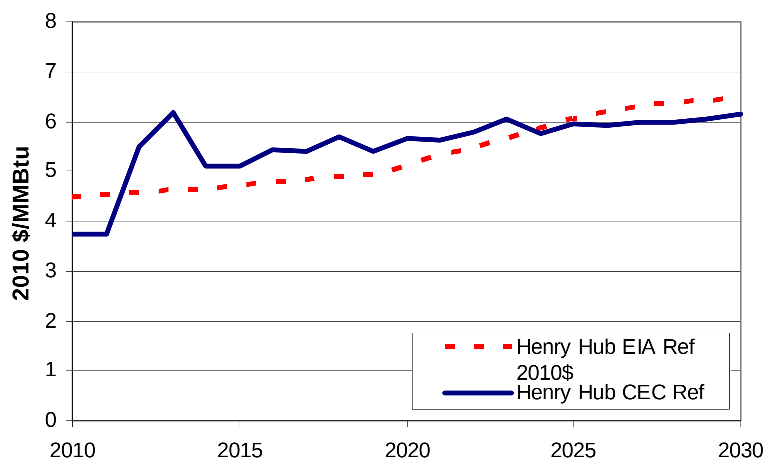
56 "Natural Gas Price Plunge Aids Families, Businesses," Associated Press, January 17, 2012.

Figure 11: Energy Commission Reference Natural Gas Price Forecast



Source: Joint Committee Workshop on Natural Gas Market Assessment Reference Case and Scenario Results, September 27, 2011.[57]

Figure 12: Comparison of AEO 2011 and Energy Commission Forecast of Henry Hub Natural Gas Price



Source: ICF International, Inc.

Natural Gas Transportation Rates

The three major IOUs in the state providing retail natural gas service have intrastate transportation rates for bringing natural gas to the customer. By statute, each of the IOUs also provides an incentive rate for transporting natural gas for CHP use. This rate is lower than the cost of transporting natural gas for a customer's boiler fuel or other thermal needs.

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57 http://www.energy.ca.gov/2011_energypolicy/documents/#09272011.

This price differential represents a benefit to customers because CHP gas can be purchased at a lower price than gas for boiler fuel.

The intrastate natural gas transportation rates are based on an analysis of the current PG&E, SCE, and SDG&E natural gas transportation tariffs. The assumed loads for the analysis are based on the five customer size classes used in the CHP Market Model. The thermal-to-electric output ratio of CHP varies by technology and by size as described in detail in the later section of this chapter, "CHP Technology Cost and Performance." For this pricing analysis, the CHP gas load was estimated at 10,000 Btu/kWh. The boiler load avoided was assumed to be 5,000 Btu/kWh. The loads for each of the customer-size bins, shown in **Table** 21, were used to calculate the transportation cost for each of the three IOUs.

Table 21: Assumed Customer Gas Loads for Pricing Analysis

CHP Market Model Customer Size Bins	Nominal CHP Capacity, kW	Boiler Load, therms/month	CHP Load, therms/month
50-500 kW	175	6,388	12,775
500-1,000 kW	750	27,375	54,750
1-5 MW	3,000	109,500	219,000
5-20 MW	10,000	365,000	730,000
>20 MW	40,000	1,460,000	2,920,000

Energy Use Assumptions: Thermal Load = 5,000 Btu/kWh; CHP Load =10,000 Btu/kWh.

Source: ICF International, Inc.

The analysis was based on rate information contained in of the following existing gas transportation tariffs:

- PG&E
  - G-NT – Gas Transportation Service
  - G-EG – Gas Transportation to Cogeneration and Electric Generation
  - G-SUR – Customer Procured Gas Franchise Fee
  - G-PPPS – Public Purpose Program Surcharge
- SCG
  - G-TF – Firm Intrastate Transportation Service for Distribution Customers with separate rates for commercial/industrial use and for electric generation/cogeneration
  - G-PPPS – Public Purpose Program Surcharge
  - G-MSUR – Municipal surcharge for delivery to cities outside Los Angeles
  - G-SRF – Surcharge to fund Public Utilities Commission Reimbursement Account

- SDG&E
    - GT-NC – Natural Gas Intrastate Transportation Service for Distribution Level Noncore Customers
    - G-EG – Natural Gas Intrastate Distribution Level Transportation Service for Electric Generation Customers (CHP rate)
    - G-PUC -- Public Utilities Commission Reimbursement Fee
    - G-PPPS – Public Purpose Program Surcharge
    - GP-SUR – Franchise Surcharge

Table 22 shows the calculated transportation rates for each IOU and each CHP customer size class for general use and for CHP use. These rates are before tax rates and municipal surcharges that are applied to both the commodity plus transportation rate. The CHP gas tariffs are between $0.44-$2.47/MMBtu lower than the standard transportation rates. SDG&E does not offer a volume discount on transportation, so the differentials are largest for SDG&E. For PG&E and SCE, the transportation costs get lower as the volume increases, and the corresponding comparative rate incentive for CHP customers declines.

Table 22: California Intrastate Gas Transportation Costs ($/MMBtu)

Utility/Customer Size Classes	50-500 kW	500-1,000 kW	1-5 MW	5-20 MW	>20 MW
Boiler Load					
PG&E	$2.46	$2.18	$1.74	$1.34	$0.93
SCG	$2.34	$1.79	$1.27	$0.85	$0.69
SDG&E	$3.18	$2.75	$2.66	$2.64	$2.63
CHP Load					
PG&E	$0.52	$0.35	$0.31	$0.29	$0.30
SCG	$0.61	$0.58	$0.57	$0.25	$0.25
SDG&E	$0.71	$0.68	$0.67	$0.35	$0.35

Note: Does not include 1-2 percent franchise surcharge and 7-9 percent state taxes.

Source: ICF International, Inc.

The analysis assumes that transportation costs are fixed in real dollars throughout the forecast period. This assumption does not consider the possible real increases due to the CPUC order that gas utilities are required to conduct pressure tests on all pipelines with inadequate records and replace gas lines with unsatisfactory test results.[58] PG&E and Sempra (representing SoCalGas and SDG&E) are proposing that all costs for testing and possible line replacement be added to the rate base. Therefore, there is a potential for real cost increases in gas transportation to occur.

Natural Gas Retail Rate Forecast

For this analysis the natural gas delivery costs are assumed to be constant in real dollars. The forecast of delivered gas commodity and transportation charges is the sum of the Henry Hub price plus or minus the California locational differentials plus the transportation charge. This quantity is then multiplied by one plus the appropriate franchise surcharge. **Table 23** shows the delivered boiler fuel prices and CHP prices in five-year averages.[59]

Table 23: Boiler and CHP Delivered Natural Gas Price Forecast

		Boiler Fuel Price, $/MMBtu			CHP Fuel Price, $/MMBtu		
CHP Size Class	Time Period	PG&E	SCG	SDG&E	PG&E	SCG	SDG&E
50-500 kW	2011-2015	$7.15	$7.38	$8.23	$5.18	$5.61	$5.72
	2016-2020	$7.45	$7.69	$8.54	$5.48	$5.92	$6.02
	2021-2025	$8.23	$8.48	$9.33	$6.26	$6.71	$6.81
	2026-2030	$8.95	$9.20	$10.05	$6.98	$7.43	$7.53
500-1,000 kW	2011-2015	$6.87	$6.81	$7.80	$5.01	$5.58	$5.69
	2016-2020	$7.17	$7.12	$8.11	$5.32	$5.89	$5.99
	2021-2025	$7.96	$7.91	$8.90	$6.10	$6.68	$6.78
	2026-2030	$8.67	$8.63	$9.62	$6.81	$7.39	$7.50
1-5 MW	2011-2015	$6.41	$6.29	$7.70	$4.96	$5.57	$5.68
	2016-2020	$6.72	$6.59	$8.01	$5.27	$5.88	$5.99
	2021-2025	$7.50	$7.38	$8.80	$6.05	$6.67	$6.77
	2026-2030	$8.22	$8.10	$9.52	$6.77	$7.39	$7.49
5-20 MW	2011-2015	$6.01	$5.86	$7.68	$4.95	$5.25	$5.35
	2016-2020	$6.32	$6.17	$7.99	$5.25	$5.55	$5.66
	2021-2025	$7.10	$6.96	$8.78	$6.03	$6.34	$6.44
	2026-2030	$7.82	$7.68	$9.50	$6.75	$7.06	$7.16
>20 MW	2011-2015	$5.60	$5.69	$7.67	$4.95	$5.24	$5.35
	2016-2020	$5.91	$6.00	$7.98	$5.26	$5.55	$5.66
	2021-2025	$6.69	$6.79	$8.77	$6.04	$6.34	$6.44
	2026-2030	$7.40	$7.51	$9.49	$6.76	$7.06	$7.16

Source: ICF International, Inc.

58 *Decision Determining Maximum Allowable Operating Pressure Methodology and Requiring Filing of Natural Gas Transmission Pipeline Replacement or Testing Implementation Plans, California Public Utility Commission*, Order Instituting Rulemaking 11-02-019, February 24, 2011.

59 The CHP 20-year market forecast is in four 5-year increments.

Electricity Prices

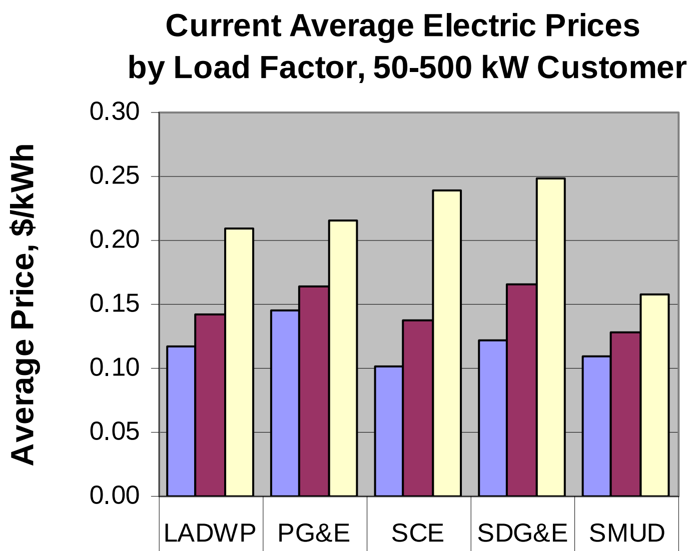
The project team analyzed the current electricity tariffs applicable for the range of customer sizes appropriate to the selection of CHP from 50 kW to larger than 20 MW. Current electricity tariffs were analyzed for the three major IOUs, SCE, PG&E, and SDG&E, and the two largest municipal utilities, 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.

Current Retail Electric Rates

The existing retail rates by size classification are shown in **Figure 14**, **Figure 15**, and **Figure** 16**.**

All rates show increasing costs as load factor decreases, and, for the most part, larger customers pay lower rates. PG&E high load factor rates are the highest in the state except for transmission-level service for very large customers. SDG&E has the next most expensive high load factor rates. Below SDG&E are the rates of the two large municipal utilities, LADWP and SMUD. SCE now has the lowest rates in the state within the size categories analyzed. SCE and SDG&E show the highest peak load air conditioning rates. SMUD rates are least sensitive to customer load factor.

Figure 13: Average Retail Electric Prices by Load Factor, 50-500 kW



	LADWP	PG&E	SCE	SDG&E	SMUD
High Load Factor	$0.1166	$0.1447	$0.1020	$0.1212	$0.1094
Low Load Factor	$0.1414	$0.1638	$0.1378	$0.1662	$0.1274
Peak AC	$0.2100	$0.2150	$0.2390	$0.2478	$0.1574

Rate Classification:

LADWP: A-2b Primary.

PG&E: A-10 TOU Secondary.

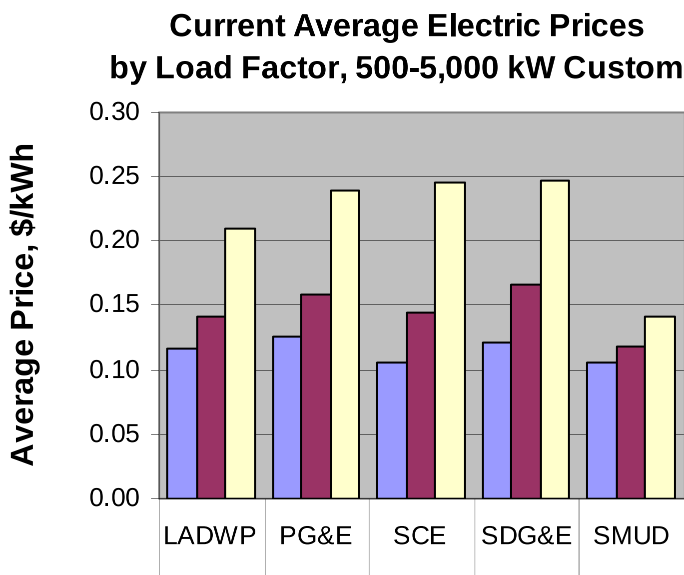
SCE: GS-3TOU Secondary.

SDG&E: AL-TOU Secondary.

SMUD: GS-TOU3 Secondary.

Source: ICF, International, Inc. Rate Analysis.

Figure 14: Average Retail Electric Prices by Load Factor, 500-5,000 kW



	LADWP	PG&E	SCE	SDG&E	SMUD
High Load Factor	$0.1165	$0.1255	$0.1062	$0.1210	$0.1056
Low Load Factor	$0.1414	$0.1590	$0.1448	$0.1657	$0.1188
Peak AC	$0.2098	$0.2391	$0.2452	$0.2468	$0.1408

Rate Classification:

LADWP: A-2b Primary.

PG&E: E-20 Secondary.

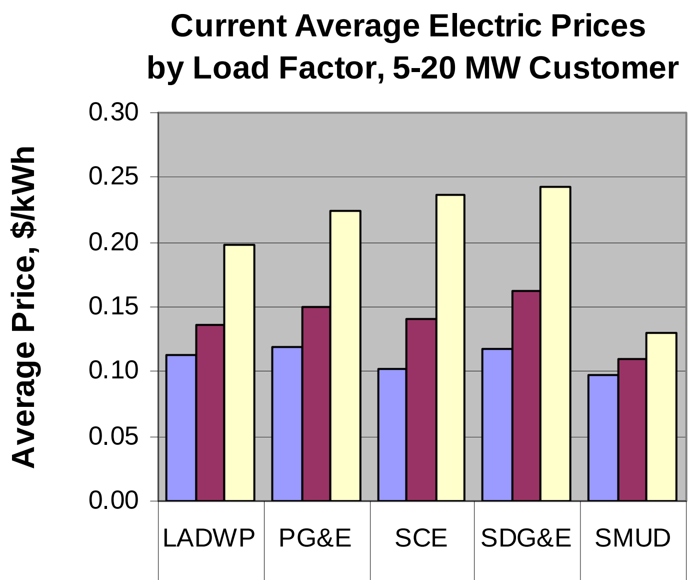
SCE: GS 8-TOU Secondary.

SDG&E: AL-TOU Secondary.

SMUD: GS-TOU1 Secondary.

Source: ICF, International, Inc. Rate Analysis.

Figure 15: Average Retail Electric Prices by Load Factor, 55-20 MW



	LADWP	PG&E	SCE	SDG&E	SMUD
High Load Factor	$0.1134	$0.1197	$0.1025	$0.1181	$0.0976
Low Load Factor	$0.1360	$0.1504	$0.1400	$0.1622	$0.1096
Peak AC	$0.1984	$0.2241	$0.2368	$0.2422	$0.1296

Rate Classification:

LADWP: A-3a Subtransmission.

PG&E: E-20 Primary.

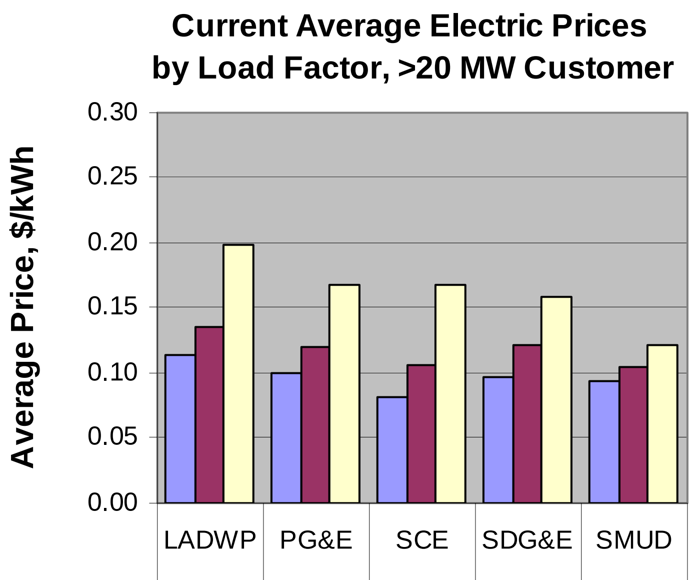
SCE: GS 8-TOU Primary.

SDG&E: AL-TOU Primary.

SMUD: GS-TOU1 Primary.

Source: ICF, International, Inc. Rate Analysis.

Figure 16: Average Retail Electric Prices by Load Factor, More Than 20 MW



	LADWP	PG&E	SCE	SDG&E	SMUD
High Load Factor	$0.1134	$0.0997	$0.0811	$0.0966	$0.0942
Low Load Factor	$0.1360	$0.1199	$0.1065	$0.1217	$0.1044
Peak AC	$0.1983	$0.1678	$0.1675	$0.1585	$0.1216

Rate Classification:

LADWP: A-3a Subtransmission.

PG&E: E-20- Transmission.

SCE: GS 8-TOU Transmission.

SDG&E: AL-TOU-Subtransmission.

SMUD: GS-TOU1 Transmission.

Source: ICF, International, Inc. Rate Analysis.

Average Avoidable Rate for CHP

A retail customer generating his own power with an on-site CHP system cannot save his entire retail rate. Therefore, it is important in evaluating the economic competitiveness of CHP to use only that portion of the electric bill that is saved by the operation of CHP, defined in this analysis as the *average avoidable rate*. Retail electric customers installing CHP are subject to standby charges and departing load charges. In addition, demand charges in a customer's rate are more difficult to avoid for CHP. A momentary outage will trigger the demand charge for the entire month. While a CHP system operating 95 percent of the time can avoid 95 percent of the energy charges, except for departing load charges, this same CHP system might avoid only 8 to 9 of 12 monthly demand charges because of outages that occur during the demand period. In this analysis the CHP system was assumed to have a 95 percent availability factor and to have three outages during the year. One outage is assumed to be a planned maintenance outage and two are assumed to be unplanned forced outages. Where the customer rates allow for advanced scheduling of CHP system maintenance, no additional demand charges for the outage are incurred.

The exemption of CHP to capacity reservation charges for the three IOUs ended in June 2011. Each IOU has a standby tariff. The SDG&E and SCE standby tariffs are riders that are added onto the customer's otherwise applicable rate. The PG&E standby tariff replaces the customer's otherwise applicable rate for standby capacity — that capacity that is ordinarily met by the generator. All of these rates have a capacity reservation charge based on the capacity of the CHP generator. SDG&E capacity reservation charge is the highest at $7.70-$7.95/kW. SCE reservation charge is $5.12/kW and PG&E is $2.75/kW. LADWP and SMUD have charges of $4-$5/kW and $4.95-$6.25/kW, respectively.

While all five utilities have either a capacity reservation charge or a facilities demand charge, which must be paid every month on the generator capacity, PG&E has no other demand charges. Under the PG&E standby rate, if the generator has an outage, the customer must pay high energy rates, more than twice standard energy rates, but the PG&E customer does not have to pay any additional demand charges. The justification for this is that CHP customers as a class represent a diversity of load, and they are not expected to experience outages all at the same time. The other utility rates do impose additional demand charges for generator outages resulting in much higher standby costs than for PG&E.

In addition to standby charges, nonbypassable customer departing load surcharges must be paid by IOU customers on all CHP output. **Table 24** shows charges for SCE and PG&E large customers on the primary distribution system. The largest component of these nonbypassable charges is the Public Purpose Program Charge. Beginning with the deregulation of the electricity industry in California in 1996, the concept of a Public Goods Charge was introduced in statute to guarantee funding for activities that may not otherwise be supported during a move toward competitive wholesale and retail markets for electricity. The funds are collected as a flat fee per kilowatt-hour of electricity usage paid by each customer, and they cover energy efficiency, renewables, and RD&D activities.

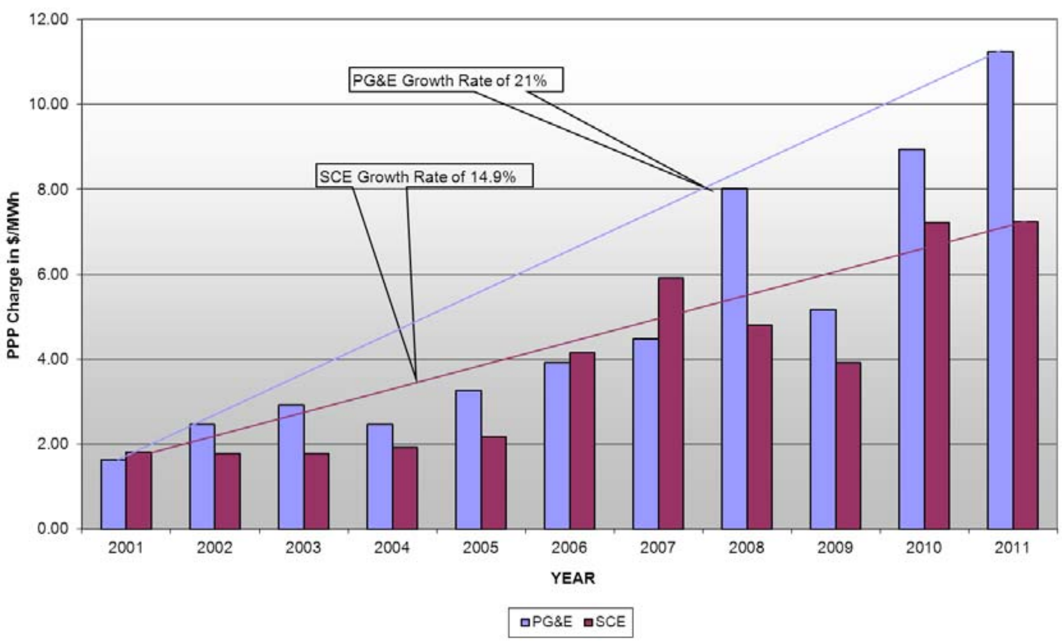
As shown in **Figure 17**, Public Purpose Program Charges have increased by 25 percent since 2006, adding greater and greater burden on CHP customers.

Table 24: Nonbypassable Charges to Utility Customers With CHP

Utility	*Charge*	*Rate ($/kWh)*
PG&E E-20 Primary	Public Purpose Program Charge	$0.01279
	Nuclear Decommissioning	$0.00066
	DWR Bond Charge	$0.00505
	Total	$0.01850
SCE TOU-8 Primary	Public Purpose Program Charge	$0.01028
	Nuclear Decommissioning	$0.00009
	DWR Bond Charge	$0.00505
	Total	$0.01542

Source: PG&E E-20 Tariff, SCE TOU-8 Tariff.

Figure 17: Growth in Public Purpose Program Surcharges



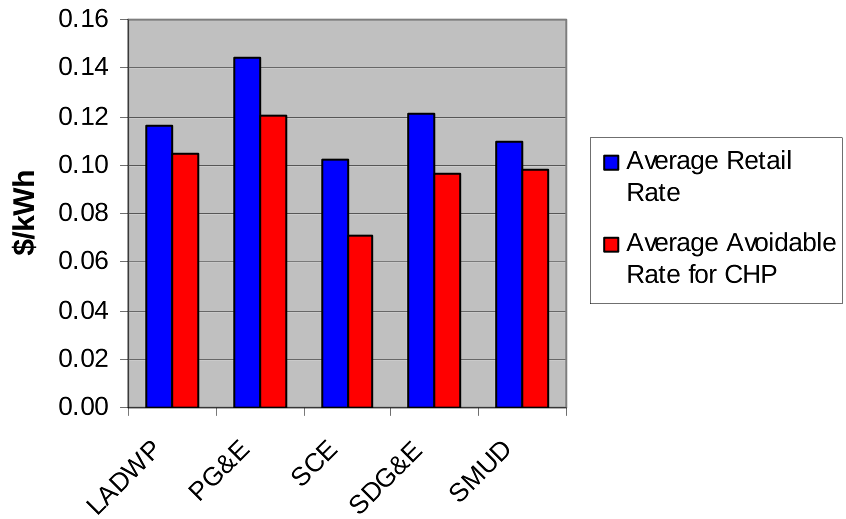
Source: Alcantar & Kahl, LLP.[60]

60 Alcantar, Michael, *California Combined Heat & Power: Barriers to Entry and Public Policies for the Maintenance of Existing & the Development of New CHP*, Alcantar and Kahl, LLP, San Francisco, California, June 21, 2011.

The project team calculated the expected average avoidable rates based on the retail rates, standby, and departing load charges for each of the five utilities. **Figure 18** shows the comparison of retail rates to CHP savings rate for a high load factor customer in the 50 – 500 kW size class. **Figure 19** shows the same comparison for the 5-20 MW customer size class. The two municipal utilities have the lowest difference between the retail rates and the CHP average avoidable rate averaging around 1.1 cents/kWh. The IOUs have the highest difference ranging from 2.3 to 3.0 cents/kWh. A CHP customer in LADWP and SMUD territories can save about 90 percent of the retail rate. A customer in one of the IOU territories can save only 70 to 80 percent of the retail rate.

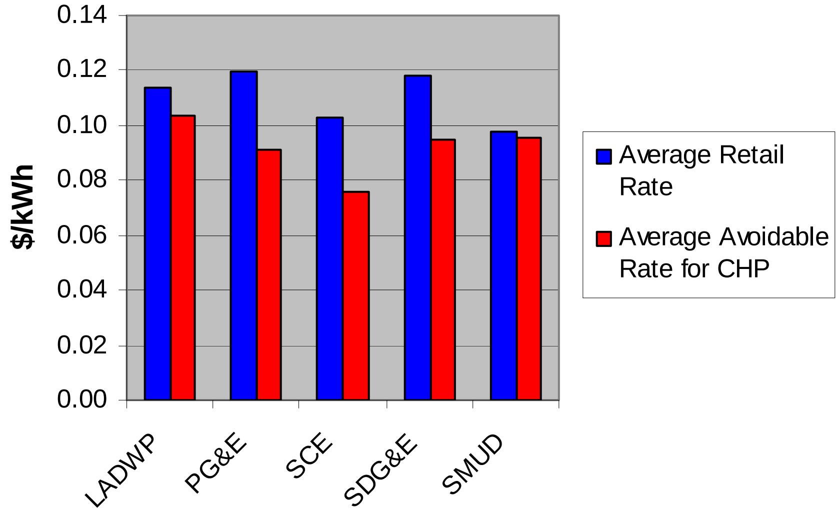
Table 25 shows the high and low load factor CHP average avoidable rate by size for the five utilities.

Figure 18: Comparison Average Retail and Average Avoidable Rates for CHP – 50-500 kW



Source: ICF Rate Analysis

Figure 19: Comparison Average Retail and Average Avoidable Rates for CHP – 5-20 MW



Source: ICF Rate Analysis

Table 25: Average CHP Average Avoidable Rate for High and Low Load Factor Applications

Size	Load Factor	LADWP	PG&E	SCE	SDG&E	SMUD
50–500 kW	High Load Factor	$0.1050	$0.1207	$0.0711	$0.0969	$0.0981
	Low Load Factor	$0.1187	$0.1349	$0.0949	$0.1282	$0.1060
	Avoided Air Conditioning	$0.1535	$0.1741	$0.1598	$0.1789	$0.1195
500–5,000 kW	High Load Factor	$0.1051	$0.0964	$0.0784	$0.0969	$0.0940
	Low Load Factor	$0.1190	$0.1257	$0.1073	$0.1282	$0.1003
	Avoided Air Conditioning	$0.1543	$0.1960	$0.1783	$0.1789	$0.1115
5–20 MW	High Load Factor	$0.1037	$0.0915	$0.0756	$0.0946	$0.0954
	Low Load Factor	$0.1170	$0.1182	$0.1039	$0.1259	$0.0994
	Avoided Air Conditioning	$0.1511	$0.1823	$0.1729	$0.1767	$0.1065
> 20 MW	High Load Factor	$0.1053	$0.0790	$0.0647	$0.0748	$0.0916
	Low Load Factor	$0.1171	$0.0966	$0.0857	$0.0845	$0.0965
	Avoided Air Conditioning	$0.1513	$0.1437	$0.1381	$0.0912	$0.1075

Source: ICF International, Inc.

Electric Rate Forecast

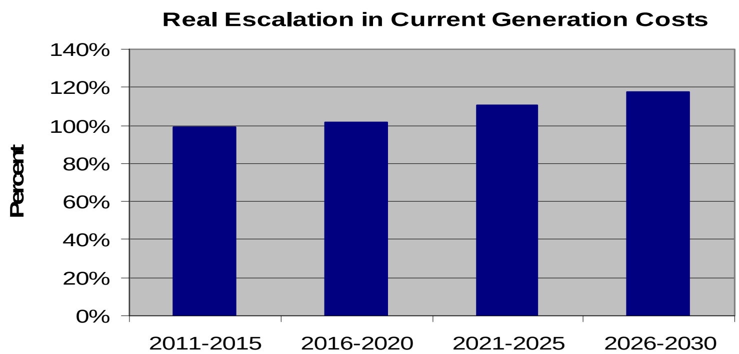
The current electric tariffs and CHP average avoidable rates are escalated in real dollars over the 20-year time horizon of the forecast. It is assumed that the transmission and delivery portion of the rates are fixed in real dollars and, therefore, do not change throughout the forecast period. The generation 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 using the electric power generation natural gas rate forecast from *AEO 2011* previously discussed. The combined cycle power plant costs are based on a recent plant addition in Southern California shown in **Table 26**. The resulting percentage change in real electricity generation price over the 20-year forecast, in 5-year average increments, is shown in **Figure 20**.

Table 26: Representative Natural Gas Combined Cycle Power Plant Costs

Combined Cycle Power Plant Assumptions	
Annual Fixed Cost $/kW-year	$211
Heat Rate, Btu/kWh	7,430
Electric Efficiency, %	45.9%
Annual Load Factor	70%

Source: ICF international, Inc.

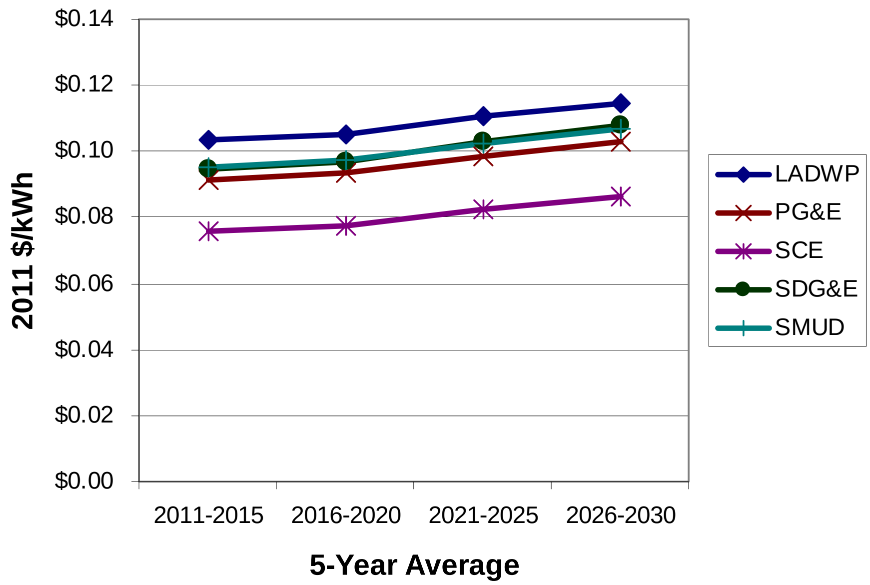
Figure 20: Real Escalation in Electricity Generation Costs



Source: ICF international, Inc.

The 20-year forecast CHP average avoidable rates are shown for the 5-20 MW case high load factor example in **Figure 21**. All utilities and size category CHP average avoidable rate forecasts are shown for high load factor, low load factor, and avoided air conditioning in **Table 27**, **Table 28**, and **Table 29,** respectively.

Figure 21: CHP Electric Average Avoidable Rate for 5 – 20 MW High Load Customers



Source: ICF International, Inc.

Table 27: CHP Average Avoidable Rate Forecast High Load Factor Customers

Customer CHP Size	5-Year Average	LADWP $/kWh	Other North $/kWh	Other South $/kWh	PG&E $/kWh	SCE $/kWh	SDG&E $/kWh	SMUD $/kWh
50-500 kW	2011-2015	$0.1050	$0.1066	$0.1066	$0.1207	$0.0711	$0.0969	$0.0981
	2016-2020	$0.1065	$0.1085	$0.1085	$0.1227	$0.0726	$0.0989	$0.1002
	2021-2025	$0.1112	$0.1142	$0.1142	$0.1289	$0.0772	$0.1052	$0.1063
	2026-2030	$0.1149	$0.1187	$0.1187	$0.1338	$0.0809	$0.1102	$0.1112
500-5,000 kW	2011-2015	$0.1051	$0.1045	$0.1045	$0.0964	$0.0784	$0.0969	$0.0940
	2016-2020	$0.1069	$0.1064	$0.1064	$0.0982	$0.0801	$0.0989	$0.0958
	2021-2025	$0.1122	$0.1121	$0.1121	$0.1036	$0.0854	$0.1052	$0.1014
	2026-2030	$0.1164	$0.1167	$0.1167	$0.1079	$0.0896	$0.1102	$0.1059
5-20 MW	2011-2015	$0.1037	$0.1045	$0.1045	$0.0915	$0.0756	$0.0946	$0.0954
	2016-2020	$0.1054	$0.1063	$0.1063	$0.0933	$0.0773	$0.0967	$0.0972
	2021-2025	$0.1106	$0.1119	$0.1119	$0.0988	$0.0824	$0.1028	$0.1025
	2026-2030	$0.1148	$0.1163	$0.1163	$0.1031	$0.0866	$0.1077	$0.1068
> 20 MW	2011-2015	$0.1038	$0.1017	$0.1017	$0.0773	$0.0632	$0.0728	$0.0899
	2016-2020	$0.1053	$0.1034	$0.1034	$0.0790	$0.0647	$0.0748	$0.0916
	2021-2025	$0.1099	$0.1084	$0.1084	$0.0839	$0.0692	$0.0810	$0.0966
	2026-2030	$0.1135	$0.1124	$0.1124	$0.0879	$0.0729	$0.0859	$0.1005

Source: ICF International, Inc.

Table 28: CHP Average Avoidable Rate Forecast Low Load Factor Customers

Customer CHP Size	5-Year Average	LADWP $/kWh	Other North $/kWh	Other South $/kWh	PG&E $/kWh	SCE $/kWh	SDG&E $/kWh	SMUD $/kWh
50-500 kW	2011-2015	$0.1187	$0.1180	$0.1180	$0.1349	$0.0949	$0.1282	$0.1060
	2016-2020	$0.1207	$0.1202	$0.1202	$0.1371	$0.0968	$0.1306	$0.1082
	2021-2025	$0.1266	$0.1268	$0.1268	$0.1439	$0.1026	$0.1381	$0.1150
	2026-2030	$0.1313	$0.1321	$0.1321	$0.1493	$0.1071	$0.1440	$0.1204
500-5,000 kW	2011-2015	$0.1190	$0.1152	$0.1152	$0.1257	$0.1073	$0.1282	$0.1003
	2016-2020	$0.1213	$0.1175	$0.1175	$0.1279	$0.1096	$0.1306	$0.1026
	2021-2025	$0.1283	$0.1247	$0.1247	$0.1343	$0.1164	$0.1381	$0.1093
	2026-2030	$0.1338	$0.1305	$0.1305	$0.1395	$0.1219	$0.1440	$0.1147
5-20 MW	2011-2015	$0.1170	$0.1136	$0.1136	$0.1182	$0.1039	$0.1259	$0.0994
	2016-2020	$0.1193	$0.1159	$0.1159	$0.1204	$0.1061	$0.1283	$0.1015
	2021-2025	$0.1262	$0.1229	$0.1229	$0.1271	$0.1129	$0.1356	$0.1080
	2026-2030	$0.1316	$0.1285	$0.1285	$0.1325	$0.1183	$0.1414	$0.1132
> 20 MW	2011-2015	$0.1171	$0.1122	$0.1122	$0.0966	$0.0857	$0.0845	$0.0965
	2016-2020	$0.1191	$0.1143	$0.1143	$0.0986	$0.0877	$0.0869	$0.0985
	2021-2025	$0.1253	$0.1207	$0.1207	$0.1046	$0.0937	$0.0942	$0.1046
	2026-2030	$0.1301	$0.1258	$0.1258	$0.1095	$0.0985	$0.1000	$0.1094

Source: ICF International, Inc.

Table 29: CHP Average Avoidable Rate Forecast CHP Avoided Air Conditioning

Customer CHP Size	5-Year Average	LADWP $/kWh	Other North $/kWh	Other South $/kWh	PG&E $/kWh	SCE $/kWh	SDG&E $/kWh	SMUD $/kWh
50-500 kW	2011-2015	$0.1535	$0.1433	$0.1433	$0.1741	$0.1598	$0.1789	$0.1195
	2016-2020	$0.1565	$0.1458	$0.1458	$0.1769	$0.1626	$0.1816	$0.1213
	2021-2025	$0.1654	$0.1533	$0.1533	$0.1852	$0.1711	$0.1898	$0.1266
	2026-2030	$0.1725	$0.1593	$0.1593	$0.1919	$0.1779	$0.1964	$0.1309
500-5,000 kW	2011-2015	$0.1543	$0.1395	$0.1395	$0.1960	$0.1783	$0.1789	$0.1115
	2016-2020	$0.1578	$0.1423	$0.1423	$0.1990	$0.1817	$0.1816	$0.1132
	2021-2025	$0.1684	$0.1506	$0.1506	$0.2079	$0.1921	$0.1898	$0.1185
	2026-2030	$0.1769	$0.1573	$0.1573	$0.2150	$0.2004	$0.1964	$0.1228
5-20 MW	2011-2015	$0.1511	$0.1352	$0.1352	$0.1823	$0.1729	$0.1767	$0.1065
	2016-2020	$0.1546	$0.1380	$0.1380	$0.1854	$0.1764	$0.1794	$0.1083
	2021-2025	$0.1652	$0.1464	$0.1464	$0.1949	$0.1867	$0.1875	$0.1136
	2026-2030	$0.1736	$0.1530	$0.1530	$0.2025	$0.1950	$0.1939	$0.1179
> 20 MW	2011-2015	$0.1513	$0.1359	$0.1359	$0.1437	$0.1381	$0.0912	$0.1075
	2016-2020	$0.1544	$0.1391	$0.1391	$0.1465	$0.1411	$0.0939	$0.1106
	2021-2025	$0.1639	$0.1490	$0.1490	$0.1550	$0.1504	$0.1020	$0.1200
	2026-2030	$0.1714	$0.1569	$0.1569	$0.1618	$0.1578	$0.1084	$0.1276

Source: ICF International, Inc.

Export Pricing

The preceding retail price analysis determined the prices used in the analysis of economic competitiveness of CHP where the power is used on-site, or as it is called "behind-the-meter." CHP systems can also export power back to the electric grid, either directly to the utility that provides their service or to another buyer. There are two categories export pricing that will be important to the California CHP market. For systems less than 20 MW, there is a newly developed FIT that was the result of AB 1613. For systems larger than 20 MW, the picture is less clear. The *QF Settlement* agreement has created a mechanism for existing QFs to move forward with a negotiated agreement on pricing and terms. There are still considerable debate and remaining uncertainty about how this mechanism will work and whether it will eventually be opened up to potential new CHP projects on an unrestricted basis.

AB-1613 Feed-in-Tariff Estimation

Power purchase and sale agreements have been developed for CHP power export under the terms of AB 1613.[61] There are two agreements, one for projects less than 20 MW and a simplified contract for projects less than 5 MW. The pricing terms are identical except for the amount of a monthly scheduling fee.

The contract specifies fixed charges and variable operating and maintenance (O&M) costs that remain in effect for the life of the contract up to a 10-year maximum. These values vary by the contract start date increasing at about 2 percent per year as shown in **Table 30**.

Table 30: AB 1613 Fixed Price and Variable O&M Payments (2011 Terms)

Year	Fixed Price $/kWh	Variable O&M $/kWh
2011	$0.02077	$0.00482
2012	$0.02113	$0.00488
2013	$0.02153	$0.00497
2014	$0.02194	$0.00507
2015	$0.02199	$0.00519
2016	$0.02204	$0.00530
2017	$0.02210	$0.00543
2018	$0.02215	$0.00555
2019	$0.02220	$0.00569
2020	$0.02224	$0.00583

Source: CPUC.

The fuel costs are based on the average of monthly midweek gas price indices as reported in *Gas Daily*, *Natural Gas Intelligence*, and *Natural Gas Weekly*. Gas transportation costs based on

61 The AB 1613 pricing estimates for this study were based on the draft contract term sheets available in October 2011. Some terms and pricing provisions have since been changed.

the EG/CHP delivery rate are added to the gas commodity price. The fuel component of the rate is equal to this gas price multiplied by a specified heat rate of 6,924 Btu/kWh.

The calculated energy rate, which is the sum of the fixed and variable charges, is then multiplied by a time-of-day (TOD) factor depending on the time of day and the month of delivery. These factors range from a low of about 0.6 at night to over 2 during super peak periods. Each utility has its own TOD factors. However, for a constant rate of export across all periods, the weighted average TOD factors in each case add up to one. Therefore, the TOD factors were not needed to calculate an average annual rate for the constant export assumption used in the model.

There is also a location bonus providing an additional 10 percent onto the energy price for capacity that comes from a *high value area* defined as a “Local Resource Adequacy” area based on the most recent California ISO *Local Capacity Technical Analysis*[62] adopted by the CPUC. For this analysis, with seven regions modeled, not specific location bonuses were assumed.

CHP customers that enter into an export contract must pay a monthly schedule coordination fee. These system costs are waived for CHP systems less than 1 MW, $1,500/month for systems 2 – 5 MW, $2,500/month for systems 5 – 10 MW, and $5,000/month for systems larger than 10 MW. **Table 31** shows the unit cost effect of these scheduling fees for the five CHP market size bins in the ICF CHP Market Model. These scheduling costs result in only a trivial reduction in the average payment price.

Table 31: Monthly Scheduling Fees for CHP Size Bins in the CHP Market Model

CHP Sizes	Nominal Capacity	CHP Load	Scheduling Fee	Unit Cost $/kWh
50-500 kW	175	12,775	$0	$0.0000
500-1,000 kW	750	54,750	$0	$0.0000
1-5 MW	3,000	219,000	$1,500	$0.0007
5-20 MW	10,000	730,000	$5,000	$0.0007
>20 MW	40,000	2,920,000	$5,000	$0.0002

Source: CPUC

For this analysis, the export prices were calculated using the average natural gas price for electricity generation in California from *AEO 2011* to be consistent with the other forecast pricing assumptions used. The fixed costs and variable O&M costs were assumed to be constant in real dollars. While pricing is currently defined only until 2020, it was assumed that the prices would be available according the same formula throughout the 20-year

62 California ISO, *2012 Local Capacity Technical Analysis, Final Report and Study Results.* April 29, 2011.

forecast period. The resulting calculated export prices by five-year averages are shown in **Table 32.**

Table 32: AB 1613 Export Price Estimates

AB-1613 Export Prices	2011-2015	2016-2020	2021-2025	2026-2030
AB-1613 FIT Basis	$0.0611	$0.0631	$0.0691	$0.0739
50-500 kW	$0.0611	$0.0631	$0.0691	$0.0739
500-1,000 kW	$0.0611	$0.0631	$0.0691	$0.0739
1-5 MW	$0.0605	$0.0624	$0.0685	$0.0732
5-20 MW	$0.0605	$0.0624	$0.0685	$0.0732
>20 MW	$0.0610	$0.0630	$0.0690	$0.0738

Source: ICF International, Inc.

The requirement for a CHP feed-in-tariff has been extended to publicly owned utilities as well. SMUD has defined a distributed generation (DG) feed-in-tariff that applies to CHP up to 5 MW. The current published rates for this tariff are shown **Table 33**. The annual average rates are very similar to the AB 1613 rates. Therefore, for the market forecast the rates calculated for AB 1613 were assumed to apply to both IOU and municipal utilities in the state.

Table 33: SMUD Distributed Generation Feed-In Tariff Pricing

SMUD DG FIT Rates, $/kWh	2011	2012	2013
Winter Off Peak	$0.0422	$0.0433	$0.0444
Winter On Peak	$0.0536	$0.0551	$0.0564
Winter Super Peak	$0.0590	$0.0606	$0.0620
Spring Off Peak	$0.0361	$0.0374	$0.0382
Spring On Peak	$0.0472	$0.0486	$0.0495
Spring Super Peak	$0.0490	$0.0505	$0.0515
Summer Off Peak	$0.0486	$0.0499	$0.0513
Summer On Peak	$0.0566	$0.0583	$0.0596
Summer Super Peak	$0.2190	$0.2235	$0.2298
Annual Average	$0.0603	$0.0619	$0.0635

Source: SMUD.

LADWP does not have a published CHP feed-in-tariff as of December 2011.

Large System CHP Export Price

The settlement agreement provides a number of options for export contracting as shown in **Table 34**. For purposes of the market forecast of new CHP capacity in California, only the options for new capacity are considered. The options for existing facilities are discussed later in this report in Chapter 3: Barriers and Incentives for Continued Production From Existing CHP.

For this analysis, all new systems less than 20 MW are assumed to select the AB 1613 pricing option. The options open to projects greater than 20 MW are for an as-available contract and the as-yet-unreleased CHP RFO. For existing facilities that are repowering, the limited-term transition PPA is also available. The as-available contracts provide for a much lower contribution to fixed costs. An RFO will select from among the best offers that the utility receives.

Table 34: CHP Seller's Options

CHP Category	Size	Contracts Available
Existing Contract	1.5 MW or less	Amendment to Legacy QF PPA
	1.5-20 MW	Amendment to Legacy QF PPA
New Contract	Less than 5 MW	QF PURPA PPA, Transition PPA, AB-1613
	5-20 MW	QF PURPA PPA, Transition PPA, AB-1613, CHP RFO
	Greater than 20 MW	CHP RFO, Transition PPA, As Available
Contract Types:		
Transition PPA: Available only to CHP facilities selling under an existing QF contract (or extension) that expires during the period from SED through July 1, 2015, and the term must end on or before July 1, 2015.		
As Available: Available only to gas-fired CHP facilities larger than 20 MW but average annual deliveries less than 131,400 MWh that meet efficiency requirement of 60% and use 75% of on-site generation.		
AB 1613: Available to AB 1613 new or retrofit facilities placed into operation after January 1, 2008.		
CHP RFO: Request for Offer for CHP systems larger than 5 MW. CHP RFO not released as of October 2011.		

Source: PG&E.

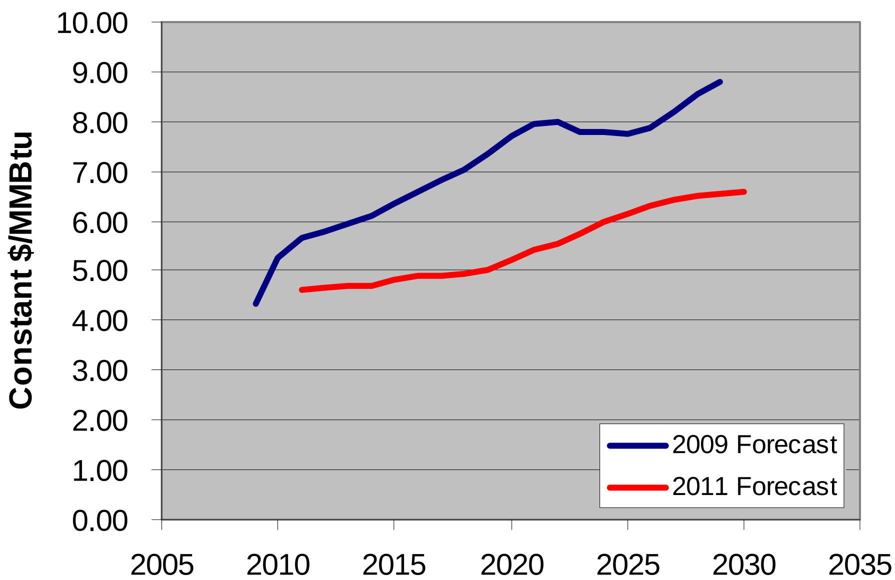
Export pricing for large CHP is part of the *QF Settlement* agreement and still under development at the time this work was undertaken. For this reason, large CHP export pricing was defined separately for each of the market scenarios and will be discussed in Chapter 3.

Comparison to 2009 Pricing Analysis

The outlook for future natural gas wellhead prices, as represented by the Henry Hub price, is significantly lower in the EIA *AEO 2011* Reference Case use for this study than in the EIA *AEO 2009* Reference Case that was used for the 2009 study as shown in **Figure 22**. The lower natural gas prices make CHP more competitive with purchased electricity. The lower natural gas prices and price escalation also lower the assumed real escalation in electricity prices.

The team calculated delivered gas prices differently for 2011 than in 2009. In 2009, only a simplified approach was used with a statewide wellhead price and assumed delivery markups based on a comparison of the EIA-AEO delivered gas prices compared to wellhead prices. For this analysis, the actual PG&E, SCE, and SDG&E gas delivery tariffs were calculated. The delivery costs calculated in this fashion are higher than what was assumed in 2009 for smaller customers and somewhat lower for the large customers. This change led to some delivered boiler prices being higher in the 2011 analysis than in 2009 in spite of the lower wellhead price assumptions. The CHP incentive rate as calculated is lower than the simplified assumptions used in 2009.

Figure 22: Comparison of 2011 and 2009 Natural Gas Wellhead Price Assumptions



Source: EIA AEO 2009 Reference Case Henry Hub Price, EIA *AEO 2011* Reference Case Henry Hub Price.

Table 35: Comparison of Delivered Gas Costs

	2014			2029		
Region	**EG/CHP**	**Industrial**	**Commercial**	**EG/CHP**	**Industrial**	**Commercial**
South 2009	$5.77	$6.98	$6.98	$7.67	$8.88	$8.88
South 2011	$5.24-$5.72	$5.86-$7.80	$7.38-$8.23	$6.80-$7.53	$7.68-$9.62	$9.20-$10.00
North 2009	$5.77	$6.98	$6.98	$7.67	$8.88	$8.88
North 2011	$4.98-$5.21	$6.05-$6.91	$7.19	$6.80-$7.03	$7.87-$8.73	$9.01

Source: ICF International, Inc.

Retail electric rates calculated for the 2011 analysis are lower for SCE and SDG&E and higher for LADWP and SMUD. PG&E rates are higher for small customers and lower for the larger customers. The standby rules have changed since 2009 with the elimination of the exemption for CHP to standby reservation charges. This change has resulted in a greater difference between average retail rates and average avoidable costs for CHP, particularly for SDG&E and SCE. SDG&E rates are lower than what was assumed in 2009, and the standby related costs are higher, further reducing the CHP average avoidable rates in all sizes. The CHP average avoidable rate for LADWP and SMUD is higher than in 2009. PG&E CHP average avoidable rates are slightly lower than in 2009.

In 2009, the CHP FIT had not been developed. The export price assumptions in 2009 for the AB 1613-eligible systems up to 20 MW were then available FIT for renewable technologies. This renewable FIT was much higher than the current CHP FIT prices due to a combination of higher gas price assumptions in 2009 and environmental credits applied to the renewable FIT that are not available to CHP. The method for estimating export prices for large CHP systems was very similar in 2009 and 2011, though the increase in prices over time is lower in 2011 due to the lower gas price forecast.

Gas and electric prices work together to determine CHP economic competitiveness, which, in turn, determines future market penetration. Adding the 2011 natural gas and electric prices into the 2009 high load factor traditional CHP market sector results in the changes to market penetration shown in **Table 36**. SCE and SDG&E reach only about 70 – 80 percent of their 2009 market estimates using the new 2011 prices compared to the 2009 price assumptions. These reductions are due to higher standby charges for CHP. All the other utility market regions show increased market penetration resulting from the lower gas prices. However, the overall impact is a 7 percent reduction in market penetration using the 2011 energy price assumptions.

Table 36: 2011 Market Penetration Compared to 2009 Results for High Load Factor Traditional CHP Market Segment

Regional Market	2011/2009 Mkt. Pen. %
LADWP	137.2%
SCE	71.4%
SDG&E	80.1%
Other South	127.4%
PG&E	104.4%
SMUD	134.2%
Other North	133.0%
Total Market	**93.2%**

Source: ICF International, Inc.

A similar comparison of using the 2011 prices in the 2009 export market forecast produces a very significant reduction in the estimate of market participation by AB 1613-eligible facilities. There is virtually no difference in the market forecast for larger systems (greater than 20 MW) because both the 2009 and 2011 forecasts were based on a similar calculation of the electric price as a function of the gas price that the facility sees. Therefore, the economic relationship between the fuel cost and output price is unchanged.

CHP Technology Cost and Performance

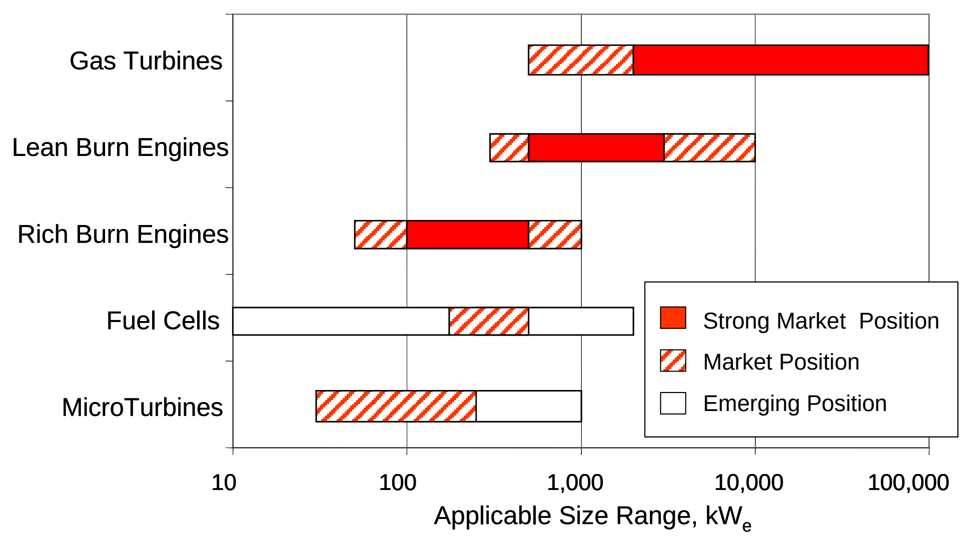
CHP systems use fuel to generate electricity and useful heat for the customer. There are many different technologies and products that are capable of doing this. While these technologies differ significantly in how they are configured and how they operate, the economic value of CHP depends on key factors common to all CHP technologies:

- Installed capital cost of the system, on a unit basis expressed in $/kWh, a special subset of capital costs are emissions treatment equipment costs needed to bring some CHP systems into compliance with California emissions requirements
- Fuel required to generate electricity — commonly expressed as the heat rate in Btu/kWh. All heat rates in this report are expressed in terms of the higher heating value (HHV) of the fuel. This is the same basis on which natural gas is measured and priced for sale. Vendors typically express engine heat rates in terms of lower heating value (LHV), which does not include the heat of vaporization of the moisture content of the exhaust. Consequently, vendor efficiency and heat rate quotes for natural gas fueled equipment are about 10-11 percent higher than when using HHV — reflecting the difference in the HHV and LHV heat contents for a given volume of natural gas.

- Useful thermal energy produced per unit of electricity output (again expressed as Btu/kWh)
- Nonfuel operating and maintenance costs, expressed on unit basis in $/kWh including annual costs and amortization of overhaul costs that can be required after a number of years of operation.
- Economic life of the equipment.
- Criteria pollutant emissions in lb/MWh and emissions treatment capital and operating costs.

This section describes the cost and performance assumptions that were used in the CHP market forecast. **Figure 23** shows the different types of CHP technologies and their competitive market range.

Figure 23: CHP Technologies and Their Competitive Market Sizes



Source: Oak Ridge National Laboratory.[63]

The CHP technologies that compete in the California market are as follows:

- Gas turbines, functionally very similar to jet engines, produce power and high quality steam for industrial and large commercial customers. Gas turbines can be as small as a few hundred kilowatts but are most economic in sizes of 5 MW and larger. In very large applications of 20 MW or more, they are used almost exclusively for systems using a gaseous fuel. Gas turbines operating under California environmental regulations must use "alter-treatment" of the exhaust in the form of selective catalytic reduction (SCR).

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

- Reciprocating engines, the type of engine used in most automobiles, are available in a very wide range of sizes from a few kW to several MW. In the figure, reciprocating engines are split into rich burn and lean burn.
    - Rich burn engines, engines that use a higher fuel to air ratio in operation, are typically used in smaller sizes and commercial CHP systems are offered around 100 kW. Historically, rich burn engine systems have been used in California as small as 10 kW. Rich burn engines are marketed with integrated emissions control systems, usually a three-way catalyst and an engine control module. Thermal energy is typically available as hot water.
    - Lean burn engines, so called because they operate with excess air to limit nitrogen oxide (NO_x) formation, are typically used in larger sizes. These systems are economic in sizes from 800-5,000 kW. Larger engines are also available. While lean burn technology reduces emissions of NO_x and other criteria pollutants, additional "after-treatment" is required to meet stringent California emissions requirements. Thermal energy is usually available as hot water, but steam recovery is also an option.
- Fuel cells represent an inherently clean class of technologies that produce electricity through electrochemical reactions on the fuel rather than by combustion. There are many different kinds of fuel cells named after the chemical make-up of their electrolyte (for example, phosphoric acid, molten carbonate, solid oxide, and solid polymer electrolyte). Phosphoric acid and molten carbonate are two types of fuel cells for which commercial products are available and in use in the California CHP market. Fuel cells are the most expensive type of CHP system, though there has been the promise, as yet unrealized, that higher volume production and technical improvements will bring the costs down significantly.
- Microturbines, as the name implies, are very small gas turbines. They have more in common, though, with truck turbochargers than with large, multistage gas turbines. Microturbines are available now in sizes from 65 to 1,000 kW. They are capable of meeting California emissions requirements without after-treatment. Microturbines have lower electrical conversion efficiencies than engines or fuel cells, but they offer more waste heat at temperatures up to 500 – 600 F.

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 about 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.[64] These estimates were updated for this study based on contacts with manufacturers and developers active in the California market. The technology characteristics are presented as five-year averages over the next 20 years. The 2010–2015 costs represent currently available cost and performance. The out-year estimates are based on the assumption of continued improvement in costs and performance.

The economic characteristics of each of these technologies are summarized in the following sections.

Emissions Requirements

California has very strict emissions standards for CHP equipment. In 2007, the California Air Resources Board set output-based pollutant emissions standards for fossil-fueled DG, as shown in **Table 37**. After January, 1, 2013, these standards will apply as well to biomass- and waste-fueled DG. DG operating as CHP is allowed to take credit for thermal energy used at the rate of 3.4 MMBtu/MWh — in other words, thermal energy is valued on the same output basis as the electric energy output. The heat recovery equipment must be integral to the system, and the overall system efficiency must be 60 percent or greater.

Table 37: ARB 2007 Fossil Fuel Emissions Standards

Pollutant	Emissions Standard, lb/MWh
NOx	0.07
CO	0.10
VOCs	0.02

Source: ARB.

All technologies included in this discussion are capable of meeting this standard. Fuel cells meet the standard easily without after-treatment. Reciprocating engines, microturbines, and gas turbines all require emissions control systems to clean up the exhaust. Rich burn engines use a three-way catalyst that operates much like the catalytic converter in a car. Microturbines are able to meet the standard, with the CHP credit, by advances in low NO_x combustion. Lean burn engines and gas turbines cannot meet the standards using low NO_x combustion alone. They must use a combination of low NO_x combustion and exhaust gas after-treatment. The system that is used is selective catalytic reduction, a process where the exhaust is treated with ammonia, which reduces the NO_x in the exhaust to nitrogen gas and water vapor. SCR systems can add up to $300/kW to the cost of the CHP system as well as adding additional O&M costs.

64 CHP Technology Characterization, EPA CHP Partnership Program, December 2007.

Reciprocating Engines

The reciprocating engine cost and performance assumptions are shown in **Table 38** and **Table 39**. The tables show the key economic and performance variables for the technologies used in the model. In addition, the net power cost is calculated using the natural gas price forecast described in the previous section and the existing federal income tax credit for CHP and the California SGIP incentive. Net power cost is equal to the unit cost of power from the CHP system after the value of the thermal energy is subtracted. The thermal energy calculation assumes the avoided boiler operates at 80 percent efficiency and that 80 – 100 percent of the useable thermal energy is actually used. The 80 percent use factor is used in the smaller systems rising up to 100 percent in the large systems that are typically sized to the steam load in industrial applications. Load factors of 80 percent are assumed for small systems and 90 percent for large systems. The net capital cost factor is based on the economic life of the equipment and a 10 percent cost of capital. Construction costs vary across the state; the average cost is 6.2 percent higher than the national average costs. Real capital costs for smaller reciprocating engines are assumed to decline over the next 20 years by 20 percent. Real capital costs for larger reciprocating engine CHP systems are assumed to decline by 10 percent over the next 20 years. These declines are expected to result from technology improvement and a more competitive market for system design and installation.

Figure 24 compares the net power costs for the reciprocating engine CHP systems over the 20-year market forecast horizon. Net power costs initially decrease and then increase as the federal income tax credit (ITC) and California SGIP are ended and natural gas prices rise.

Table 38: Small Reciprocating Engine Cost and Performance

CHP System	Characteristics	2010-2015	2016-2020	2021-2025	2026-2030
100 kW - Rich Burn with 3 way catalyst	U.S. Average Installed Cost, $/kW	$2,750	$2,475	$2,200	$2,200
	CA Installed Cost, $/kW	$2,921	$2,629	$2,337	$2,337
	After-Treatment Cost, $/kW	$0	$0	$0	$0
	Federal Tax Credit, $/kW	$292	$263	$0	$0
	Present Value SGIP, $/kW	$440	$440	$0	$0
	Net Capital Cost, $/kW	$2,190	$1,927	$2,337	$2,337
	O&M, $/kWh	$0.0220	$0.0200	$0.0183	$0.0183
	Heat Rate, Btu/kWh	12,637	11,488	10,531	10,531
	Useful Thermal, Btu/kWh	6,700	6,091	5,583	5,583
	CHP Gas Cost, $/MMBtu	$5.44	$5.75	$6.53	$7.25
	Boiler Fuel Gas Cost, $/MMBtu	$7.40	$7.71	$8.49	$9.21
	Net Power Cost, $/kWh	$0.0822	$0.0752	$0.0835	$0.0871
	Economic Life, years	15	15	15	15
800 kW - Lean Burn	U.S. Average Installed Cost, $/kW	$1,900	$1,710	$1,520	$1,520
	CA Installed Cost, $/kW	$2,018	$1,817	$1,615	$1,615
	After-Treatment Cost, $/kW	$300	$240	$180	$180
	Federal Tax Credit, $/kW	$232	$206	$0	$0
	Present Value SGIP, $/kW	$440	$440	$0	$0
	Net Capital Cost, $/kW	$1,647	$1,411	$1,795	$1,795
	O&M, $/kWh	$0.0160	$0.0140	$0.0120	$0.0120
	Heat Rate, Btu/kWh	9,760	9,750	9,225	9,225
	Useful Thermal, Btu/kWh	4,299	4,300	3,800	3,800
	CHP Gas Cost, $/MMBtu	$5.35	$5.66	$6.44	$7.16
	Boiler Fuel Gas Cost, $/MMBtu	$6.98	$7.28	$8.07	$8.79
	Net Power Cost, $/kWh	$0.0691	$0.0643	$0.0744	$0.0783
	Economic Life, years	15	15	15	15

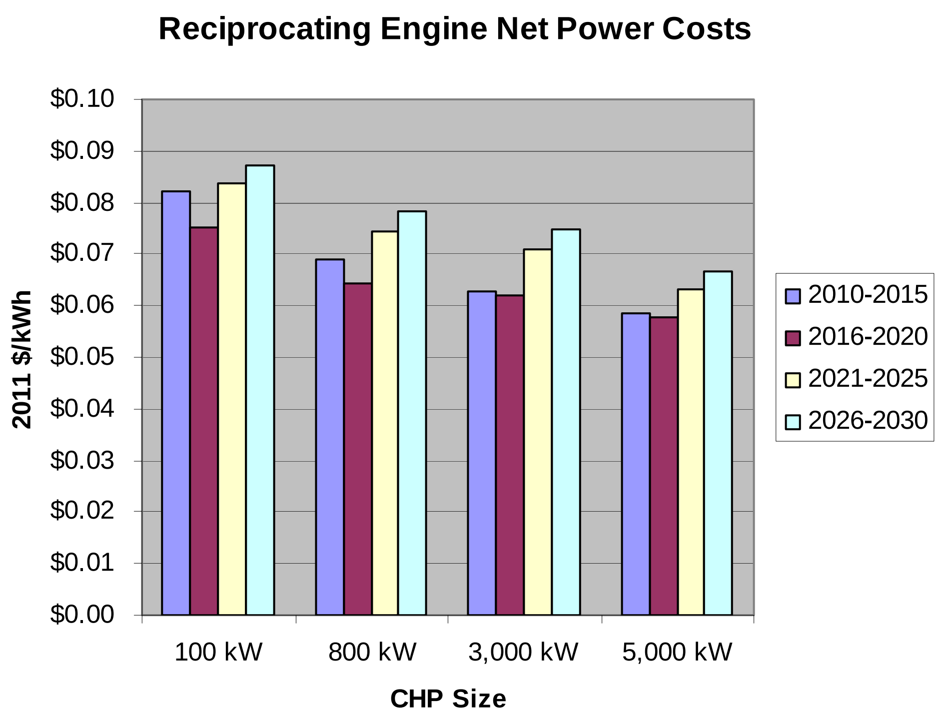
Source: ICF International, Inc.

Table 39: Large Reciprocating Engine Cost and Performance

CHP System	Characteristics	2010-2015	2016-2020	2021-2030	2026-2030
3000 kW - Lean Burn	U.S. Average Installed Cost, $/kW	$1,450	$1,378	$1,305	$1,305
	CA Installed Cost, $/kW	$1,540	$1,463	$1,386	$1,386
	After-Treatment Cost, $/kW	$200	$160	$120	$120
	Federal Tax Credit, $/kW	$174	$162	$0	$0
	Present Value SGIP, $/kW	$256	$256	$0	$0
	Net Capital Cost, $/kW	$1,310	$1,205	$1,506	$1,506
	O&M, $/kWh	$0.0160	$0.0152	$0.0145	$0.0145
	Heat Rate, Btu/kWh	9,800	9,400	9,000	9,000
	Useful Thermal, Btu/kWh	4,200	3,850	3,500	3,500
	CHP Gas Cost, $/MMBtu	$5.33	$5.63	$6.42	$7.14
	Boiler Fuel Gas Cost, $/MMBtu	$6.54	$6.85	$7.64	$8.35
	Net Power Cost, $/kWh	$0.0627	$0.0620	$0.0708	$0.0748
	Economic Life, years	20	20	20	20
5000 kW - Lean Burn	U.S. Average Installed Cost, $/kW	$1,450	$1,378	$1,305	$1,305
	CA Installed Cost, $/kW	$1,540	$1,463	$1,386	$1,386
	After-Treatment Cost, $/kW	$150	$120	$90	$80
	Federal Tax Credit, $/kW	$169	$158	$0	$0
	Present Value SGIP, $/kW	$103	$103	$0	$0
	Net Capital Cost, $/kW	$1,419	$1,322	$1,476	$1,466
	O&M, $/kWh	$0.0140	$0.0133	$0.0127	$0.0127
	Heat Rate, Btu/kWh	8,486	8,325	7,935	7,935
	Useful Thermal, Btu/kWh	3,073	2,950	2,700	2,700
	CHP Gas Cost, $/MMBtu	$5.13	$5.44	$6.22	$6.94
	Boiler Fuel Gas Cost, $/MMBtu	$6.19	$6.49	$7.28	$8.00
	Net Power Cost, $/kWh	$0.0585	$0.0579	$0.0633	$0.0666
	Economic Life, years	20	20	20	20

Source: ICF International, Inc.

Figure 24: Reciprocating Engine Net Power Costs



Source: ICF International, Inc.

Gas Turbines

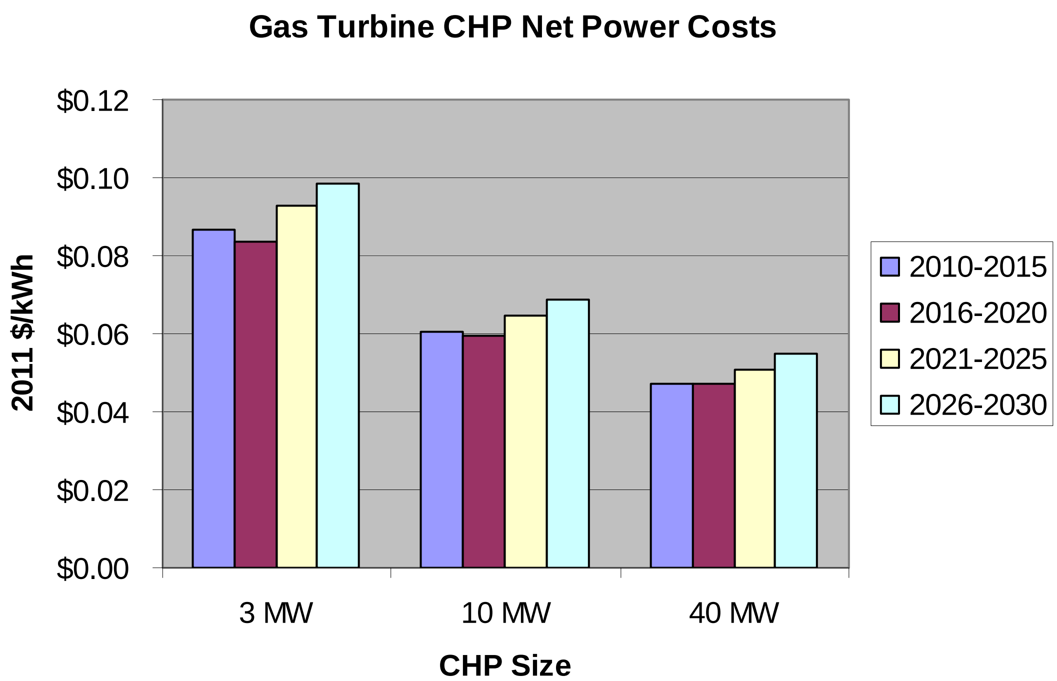
Gas turbine cost and performance characteristics and net power costs are shown in **Figure** 25 and **Table 40**. The same assumptions on load factor, thermal use factors, natural gas costs, avoided boiler efficiency, and cost of capital are used. The 3 MW gas turbine CHP system has net power costs that are higher than can be supplied by a 3 MW reciprocating engine. However, such systems may be used in applications that require a high quality steam. The 40 MW gas turbine CHP system is capable of delivering electric power at a net power cost of around 5 cents/kWh after the value of thermal energy is subtracted. These large systems are very competitive in the California market.

Table 40: Gas Turbine CHP Cost and Performance

CHP System	Characteristic/Year Available	2010-2015	2016-2020	2021-2030	2021-2030
3000 KW GT	U.S. Average Installed Cost, $/kW	$2,450	$2,328	$2,205	$2,205
	CA Installed Cost, $/kW	$2,603	$2,473	$2,342	$2,342
	After-Treatment Cost, $/kW	$365	$292	$219	$219
	Federal Tax Credit, $/kW	$297	$276	$0	$0
	Present Value SGIP, $/kW	$256	$256	$0	$0
	Net Capital Cost, $/kW	$2,415	$2,232	$2,561	$2,561
	O&M, $/kWh	$0.0100	$0.0095	$0.0091	$0.0091
	Heat Rate, Btu/kWh	14,085	13,414	12,805	12,805
	Useful Thermal, Btu/kWh	5,947	5,664	5,406	5,406
	CHP Gas Cost, $/MMBtu	$5.33	$5.63	$6.42	$7.14
	Boiler Fuel Gas Cost, $/MMBtu	$6.54	$6.85	$7.64	$8.35
	Net Power Cost, $/kWh	$0.0866	$0.0837	$0.0929	$0.0982
	Economic Life, years	20	20	20	20
10 MW GT	U.S. Average Installed Cost, $/kW	$1,520	$1,444	$1,368	$1,368
	CA Installed Cost, $/kW	$1,615	$1,534	$1,453	$1,453
	After-Treatment Cost, $/kW	$180	$144	$108	$80
	Federal Tax Credit, $/kW	$179	$168	$0	$0
	Present Value SGIP, $/kW	$103	$103	$0	$0
	Net Capital Cost, $/kW	$1,513	$1,408	$1,561	$1,533
	O&M, $/kWh	$0.0088	$0.0084	$0.0080	$0.0080
	Heat Rate, Btu/kWh	11,765	10,800	9,950	9,950
	Useful Thermal, Btu/kWh	4,674	4,062	3,630	3,630
	CHP Gas Cost, $/MMBtu	$5.13	$5.44	$6.22	$6.94
	Boiler Fuel Gas Cost, $/MMBtu	$6.19	$6.49	$7.28	$8.00
	Net Power Cost, $/kWh	$0.0605	$0.0596	$0.0648	$0.0686
	Economic Life, years	20	20	20	20
40 MW GT	U.S. Average Installed Cost, $/kW	$1,170	$1,141	$1,112	$1,112
	CA Installed Cost, $/kW	$1,243	$1,212	$1,181	$1,181
	After-Treatment Cost, $/kW	$80	$64	$48	$80
	Federal Tax Credit, $/kW	$50	$48	$0	$0
	Present Value SGIP, $/kW	$19	$19	$0	$0
	Net Capital Cost, $/kW	$1,254	$1,209	$1,229	$1,261
	O&M, $/kWh	$0.0050	$0.0050	$0.0050	$0.0050
	Heat Rate, Btu/kWh	9,220	8,990	8,759	8,759
	Useful Thermal, Btu/kWh	3,189	3,109	3,030	3,030
	CHP Gas Cost, $/MMBtu	$5.14	$5.44	$6.23	$6.94
	Boiler Fuel Gas Cost, $/MMBtu	$5.94	$6.24	$7.03	$7.75
	Net Power Cost, $/kWh	$0.0470	$0.0473	$0.0508	$0.0549
	Economic Life, years	20	20	20	20

Source: ICF International, Inc.

Figure 25: Gas Turbine CHP Net Power Costs



Source: ICF International, Inc.

Microturbines

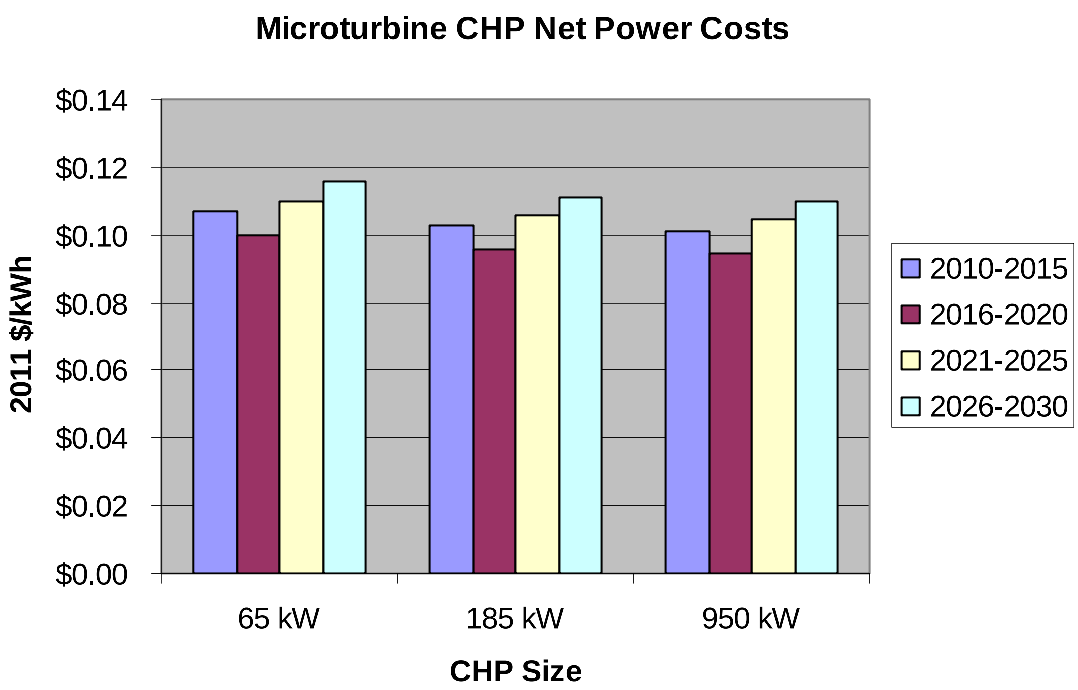
The cost and performance estimates for microturbines are shown in **Table 41** and **Figure 26**. Microturbines compete in smaller CHP applications. Microturbines are somewhat more costly to purchase and operate than similarly sized reciprocating engine systems. They have offered lower emissions, an advantage that has been reduced as reciprocating engine emissions control has improved. Microturbine systems can also be configured to offer higher temperature waste heat than reciprocating engines, though in most applications, this feature is not required or used with the systems delivering hot water in the same temperature range as reciprocating engine systems.

Table 41: Microturbine CHP Cost and Performance

CHP System	Characteristics	2010-2015	2016-2020	2021-2030	2021-2030
65 kW	U.S. Average Installed Cost, $/kW	$3,100	$2,790	$2,480	$2,480
	CA Installed Cost, $/kW	$3,293	$2,964	$2,635	$2,635
	After-Treatment Cost, $/kW	$0	$0	$0	$0
	Federal Tax Credit, $/kW	$329	$296	$0	$0
	Present Value SGIP, $/kW	$440	$440	$0	$0
	Net Capital Cost, $/kW	$2,524	$2,228	$2,635	$2,635
	O&M, $/kWh	$0.0250	$0.0227	$0.0208	$0.0208
	Heat Rate, Btu/kWh	13,950	13,286	12,682	12,682
	Useful Thermal, Btu/kWh	5,562	5,297	5,056	5,056
	CHP Gas Cost, $/MMBtu	$5.44	$5.75	$6.53	$7.25
	Boiler Fuel Gas Cost, $/MMBtu	$7.40	$7.71	$8.49	$9.21
	Net Power Cost, $/kWh	$0.1071	$0.1000	$0.1101	$0.1156
	Economic Life, years	15	15	15	15
185 KW	U.S. Average Installed Cost, $/kW	$3,000	$2,700	$2,400	$2,400
	CA Installed Cost, $/kW	$3,187	$2,868	$2,550	$2,550
	After-Treatment Cost, $/kW	$0	$0	$0	$0
	Federal Tax Credit, $/kW	$319	$287	$0	$0
	Present Value SGIP, $/kW	$440	$440	$0	$0
	Net Capital Cost, $/kW	$2,429	$2,142	$2,550	$2,550
	O&M, $/kWh	$0.0220	$0.0200	$0.0183	$0.0183
	Heat Rate, Btu/kWh	12,247	11,663	11,133	11,133
	Useful Thermal, Btu/kWh	4,265	4,062	3,877	3,877
	CHP Gas Cost, $/MMBtu	$5.44	$5.75	$6.53	$7.25
	Boiler Fuel Gas Cost, $/MMBtu	$7.40	$7.71	$8.49	$9.21
	Net Power Cost, $/kWh	$0.1026	$0.0959	$0.1060	$0.1112
	Economic Life, years	15	15	15	15
925 kW	U.S. Average Installed Cost, $/kW	$2,900	$2,610	$2,320	$2,320
	CA Installed Cost, $/kW	$3,081	$2,773	$2,465	$2,465
	After-Treatment Cost, $/kW	$0	$0	$0	$0
	Federal Tax Credit, $/kW	$308	$277	$0	$0
	Present Value SGIP, $/kW	$440	$440	$0	$0
	Net Capital Cost, $/kW	$2,333	$2,056	$2,465	$2,465
	O&M, $/kWh	$0.0200	$0.0182	$0.0167	$0.0167
	Heat Rate, Btu/kWh	12,247	11,663	11,133	11,133
	Useful Thermal, Btu/kWh	4,265	4,062	3,877	3,877
	CHP Gas Cost, $/MMBtu	$5.33	$5.63	$6.42	$7.14
	Boiler Fuel Gas Cost, $/MMBtu	$6.54	$6.85	$7.64	$8.35
	Net Power Cost, $/kWh	$0.1011	$0.0946	$0.1048	$0.1100
	Economic Life, years	15	15	15	15

Source: ICF International, Inc.

Figure 26: Microturbine CHP Net Power Costs



Source: ICF International, Inc.

Fuel Cells

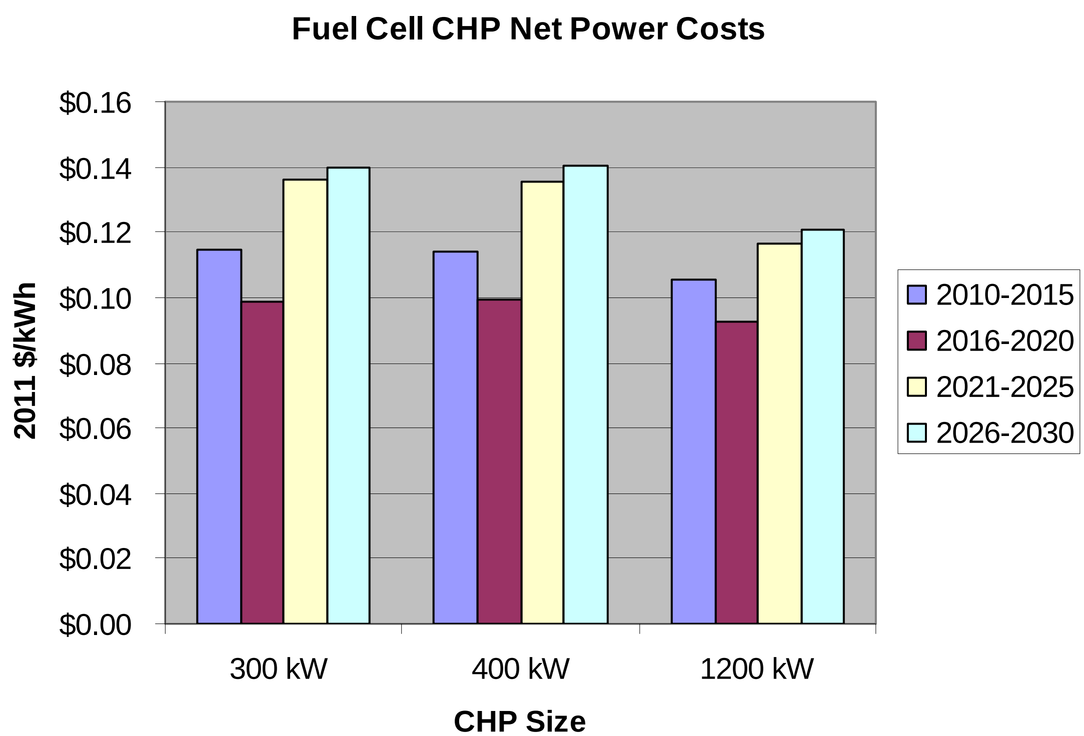
Fuel cell CHP system cost and performance are shown in **Table 42**. Fuel cells offer high electric efficiency, making them better suited to applications with low thermal energy requirements. They also offer very low emissions of criteria pollutants. Capital costs remain high as do maintenance costs resulting from the need for expensive stack replacements. Capital costs are so high currently that, even with the extra 30 percent federal income tax credit and the four times larger SGIP incentive, these systems still result in higher net power costs than conventional reciprocating engine systems.

Table 42: Fuel Cell CHP Cost and Performance

CHP System	Characteristic/Year Available	2010-2015	2016-2020	2021-2030	2021-2030
300 kW MCFC	U.S. Average Installed Cost, $/kW	$5,600	$4,760	$3,920	$3,920
	CA Installed Cost, $/kW	$5,949	$5,057	$4,164	$4,164
	After-Treatment Cost, $/kW	$0	$0	$0	$0
	Federal Tax Credit, $/kW	$1,191	$924	$0	$0
	Present Value SGIP, $/kW	$1,978	$1,978	$0	$0
	Net Capital Cost, $/kW	$2,780	$2,155	$4,164	$4,164
	O&M, $/kWh	$0.0350	$0.0304	$0.0269	$0.0269
	Heat Rate, Btu/kWh	8,022	7,640	7,293	7,293
	Useful Thermal, Btu/kWh	2,148	2,046	1,953	1,953
	CHP Gas Cost, $/MMBtu	$5.44	$5.75	$6.53	$7.25
	Boiler Fuel Gas Cost, $/MMBtu	$7.40	$7.71	$8.49	$9.21
	Net Power Cost, $/kWh	$0.1149	$0.0990	$0.1361	$0.1399
	Economic Life, years	15	15	15	15
200/400 kW PAFC	U.S. Average Installed Cost, $/kW	$5,000	$4,250	$3,500	$3,500
	CA Installed Cost, $/kW	$5,312	$4,515	$3,718	$3,718
	After-Treatment Cost, $/kW	$0	$0	$0	$0
	Federal Tax Credit, $/kW	$1,000	$761	$0	$0
	Present Value SGIP, $/kW	$1,978	$1,978	$0	$0
	Net Capital Cost, $/kW	$2,334	$1,776	$3,718	$3,718
	O&M, $/kWh	$0.0350	$0.0304	$0.0269	$0.0269
	Heat Rate, Btu/kWh	9,975	9,500	9,068	9,068
	Useful Thermal, Btu/kWh	2,608	2,484	2,371	2,371
	CHP Gas Cost, $/MMBtu	$5.44	$5.75	$6.53	$7.25
	Boiler Fuel Gas Cost, $/MMBtu	$7.40	$7.71	$8.49	$9.21
	Net Power Cost, $/kWh	$0.1137	$0.0992	$0.1358	$0.1406
	Economic Life, years	15	15	15	15
1200 kW MCFC	U.S. Average Installed Cost, $/kW	$4,820	$4,097	$3,374	$3,374
	CA Installed Cost, $/kW	$5,120	$4,352	$3,584	$3,584
	After-Treatment Cost, $/kW	$0	$0	$0	$0
	Federal Tax Credit, $/kW	$1,143	$912	$0	$0
	Present Value SGIP, $/kW	$1,312	$1,312	$0	$0
	Net Capital Cost, $/kW	$2,666	$2,128	$3,584	$3,584
	O&M, $/kWh	$0.0320	$0.0278	$0.0246	$0.0246
	Heat Rate, Btu/kWh	8,022	7,640	7,293	7,293
	Useful Thermal, Btu/kWh	2,124	2,023	1,931	1,931
	CHP Gas Cost, $/MMBtu	$5.33	$5.63	$6.42	$7.14
	Boiler Fuel Gas Cost, $/MMBtu	$6.54	$6.85	$7.64	$8.35
	Net Power Cost, $/kWh	$0.1055	$0.0927	$0.1168	$0.1206
	Economic Life, years	20	20	20	20

Source: ICF International, Inc.

Figure 27: Fuel Cell CHP Net Power Costs



Source: ICF International, Inc.

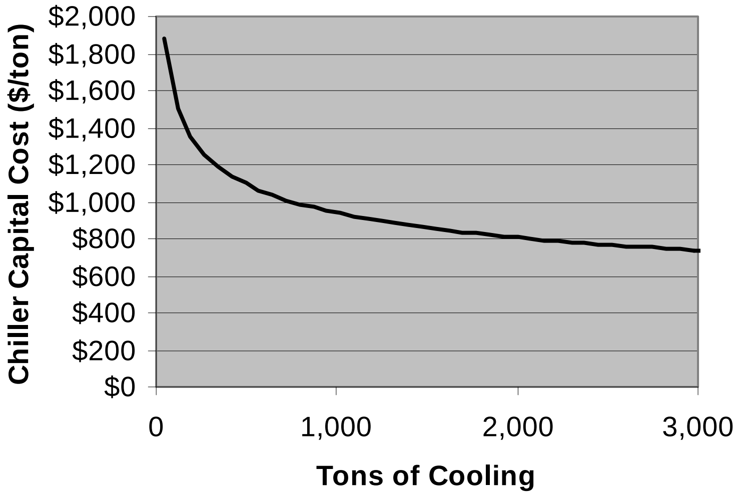
Thermally Activated Cooling Cost and Performance

CHP can also use all or a portion of its available heat energy and provide air conditioning or refrigeration, using the heat to drive absorption chillers. For cooling applications identified in the technical market potential, the costs of absorption chillers is added to the overall system costs for CHP. 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 28**. Within each CHP size bin, the costs for adding absorption cooling capacity equal to the thermal output of each system is shown in **Table 43.**

The efficiency of absorption cooling depends on the temperature of the heat source. CHP systems that provide hot water or hot pressure steam can drive single-effect absorption chillers. These systems have a cooling coefficient of performance (COP) of about 0.7 (17,000 Btu/ton of cooling). CHP systems that can provide high-pressure steam can drive double-effect absorption chillers having a COP of 1.15 (10,435 Btu/ton of cooling.)

The cost estimates for absorption cooling are the same used in the analysis of the 2009 report *Combined Heat and Power Market Assessment*.[65]

Figure 28: Absorption Chiller Cost Fitting Curve



Source: ICF International.

Table 43: Range of Absorption Chiller Costs by CHP Size

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

Source: ICF International.

65 California Energy Commission, Public Interest Energy Research Program. *Combined Heat and Power Market Assessment*. Prepared by ICF International, Inc., CEC-500-2009-094-F, April 2010.

CHAPTER 3: CHP Market Forecast and Scenario Analysis

This section describes the results of the CHP market penetration analysis. The team prepared three alternative scenarios — a *Base Case, Medium Case,* and *High Case.* The Base Case reflects current market conditions and policies. The Medium and High Cases include additional CHP stimulus measures.

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 were described in Chapter 2.

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.

The scenario assumptions summarized below are described in detail in the following sections:

Common Assumptions

- CHP cost and performance as described in Chapter 2, except as noted in the High Case
- CHP Technical Market Potential as described in Chapter 2, except as noted in the High Case
- Electric and gas price assumptions with adjustments, as will be described for other policy measures
- Federal 10 percent ITC on CHP and 30 percent ITC on fuel cell systems.

Base Case

- Cap and trade
- SGIP with program expiration in January 2016
- 33 Percent Renewables Portfolio Standard (RPS)
- AB 1613 export pricing for CHP under 20 MW
- SRAC export pricing for CHP over 20 MW

Medium Case

- SGIP legislatively extended with planned phased reduction of benefits over time
    - 5 percent reduction per year for all conventional technologies – CHP technologies other than fuel cells

- 10 percent per year reduction for emerging technologies – fuel cell CHP systems – until the dollar value of the incentive equals conventional
- 33 Percent RPS (as in the Base Case)
- Stimulus for export projects larger than 20 MW
  - Pricing based on the 2011 Market Price Referent (MPR) reflecting the long-run marginal cost of power
  - Strong market response for export projects – higher market acceptance for paybacks fewer than six years
- Increase in market participation due to removal of barriers and risk by 5-20 percent

High Case

- Includes the following Medium Case Policy Assumptions
  - SGIP with planned phased reduction
  - RPS
- Reimbursement of cap-and-trade GHG allowance component of CHP fuel costs for onsite CHP
- No nonbypassable charges (NBCs) and elimination of "double" demand charges
  - NBCs are eliminated from IOU electric tariffs for CHP.
  - No CHP outage demand charges are applied when standby reservation charge is applied.
  - This increases the avoidable electric costs for CHP by 1-2 cents/kWh for the IOUs, depending on the utility and the rate category.
  - For high load factor customers, the share of avoidable charges to retail rates ranges from 89-95 percent compared to the existing rates where the share ranges from 80-90 percent.
- High electric focus electric utility participation
  - Assumed utility ownership of large CHP with greater focus on electricity production
  - Large export CHP technical potential for sites greater than 50 MW based on combined cycle technology cost and performance – effectively increasing large export potential by 50 percent
  - Same export pricing assumptions as in the Medium Case
- 10 percent California state investment tax credit – no size limit, no end date
- Competitive CHP pricing – capital costs reductions increased by an additional 10 percent to reflect learning and market competition
- Increase in market participation due to removal of barriers and risk by an additional 2-7 percent

- $50/kW-year transmission and distribution capacity deferral payment for CHP less than 20 MW

Scenario Assumptions

Thirty-Three Percent Renewables Portfolio Standard – All Cases

The 33 percent RPS requires electric utilities to achieve 33 percent renewable power capacity by 2020. While CHP is not eligible for inclusion under the RPS, increasing the share of renewable power will act to increase average power costs to California retail customers. These higher costs create a greater incentive for CHP. The assumed increase in power costs is taken from the CPUC GHG Calculator.[66] The GHG calculator allows calculation of the effects of various GHG reducing measures on retail electricity costs and on GHG emissions from the electric sector. There are a number of preloaded scenarios. The *Accelerated Policy Case* (Case 2: 33 percent RPS and high energy efficiency) shows an increase in 2020 retail power costs of $0.0164/kWh by 2020, as shown in **Table 44**. For this analysis, the cost increase was assumed to remain constant after 2020.

Table 44: Effect of 33 Percent RPS on Electric Prices

	2011-2015	2016-2020	2021-2025	2026-2030
RPS Electric Adder, $2011/kWh	$0.0049	$0.0131	$0.0164	$0.0164

Source: GHG Calculator, v3c.

Cap and Trade

The Cap-and-Trade Program, which is scheduled to begin in 2013, will affect a wide spectrum of entities. The power sector and other large emitters are faced with compliance obligations under the Cap-and-Trade Program's initial period in 2013 and 2014, with the coverage expanding in 2015 to cover more than 80 percent of the energy-related GHG emissions in California via natural gas and transportation fuel providers. Virtually everyone who uses energy in the state will be affected to some degree by this legislation

To model the effects of cap and trade on CHP market penetration, it was necessary to define the following assumptions:

- Cost of CO_2 emissions allowances over the forecast period.
- Average CO_2 emissions of electric utilities based on each utility's share of fossil-fuel power generation.

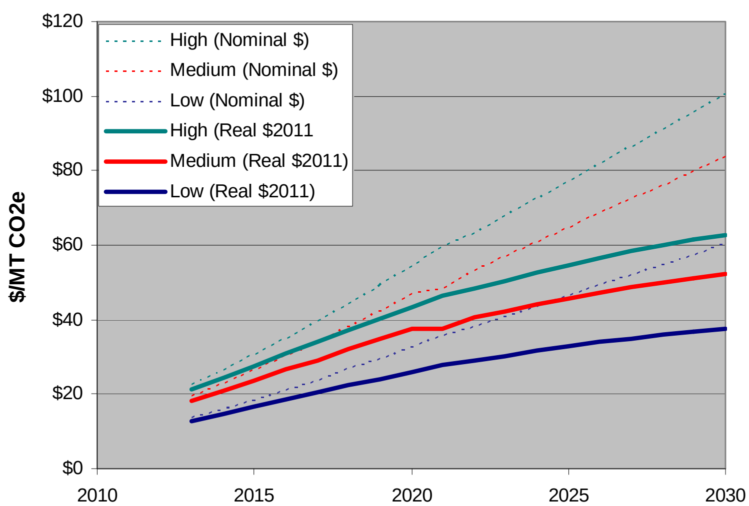
66 GHG Calculator, V3c. Energy & Environmental Economics (E3), 2011.

- The emissions for natural gas boiler fuel and CHP fuel based on the average carbon content of natural gas – 117 lb/MMBtu
- The impacts of industry allocations or utility reimbursement of auction revenues

Base and Medium Case Cap-and-Trade Assumptions

The CO2 allowance price track used in the joint IOU proposal and site rulemaking R.11-03-012 is based on the 2009 Market Price Referent (MPR) analysis, which, in turn, was based on a 2008 forecast by Synapse.[67] The Synapse price forecast, with linear extrapolation added between 2020 and 2030, is shown in **Figure 29.** The real-to-nominal dollar conversion is based on 2.5 percent per year, as specified in the MPR analysis. The Medium Case is used in the analysis.

Figure 29: CO_2 Allowance Price Forecast



Source: Adapted from Synapse, 2008.

67 Schlissel, David, et al., *Synapse 2008 CO2 Price Forecasts*, Synapse Energy Economics, Inc. Cambridge, MA, July 2008.

Table 45 shows the model real price assumptions in 5-year averages for the 20-year forecast horizon.

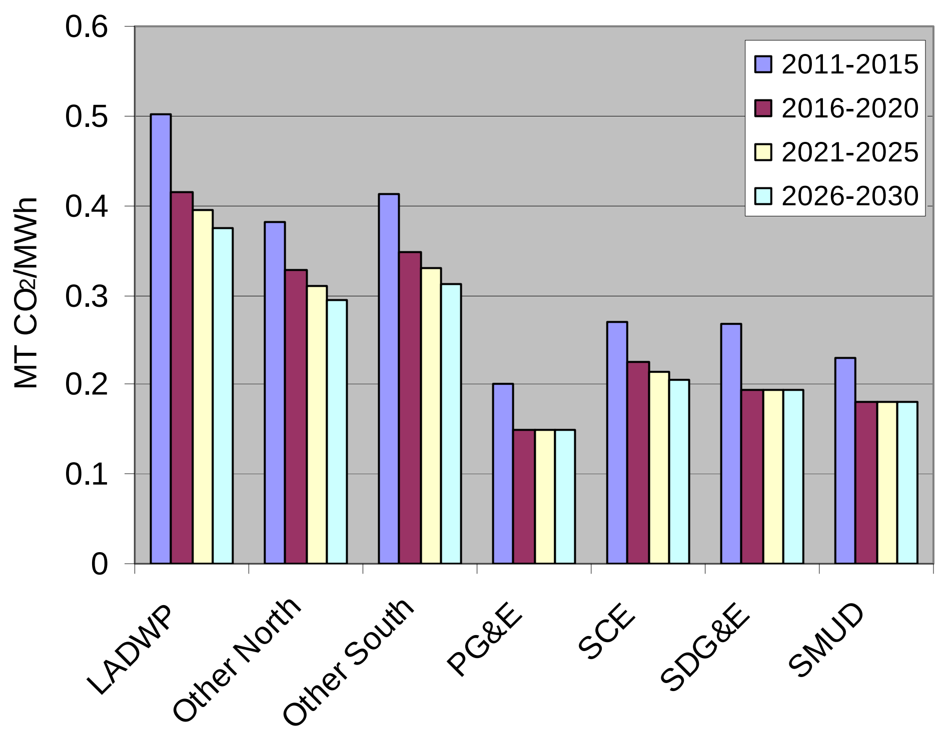
Table 45: Cap-and-Trade Credit Price Forecast

	2011-2015	2016-2020	2021-2025	2026-2030
CO_2 Trading Price, 2011 \$/MT CO_2e	\$12.61	\$31.98	\$42.06	\$49.86

Source: Adapted from Synapse, 2008.

The effect that these allowance prices have on electricity costs is based on the average fossil fuel content of electric power generation. The assumptions for GHG emissions by utility are taken from the GHG Calculator Accelerated Policy Case described in the discussion of RPS. The emissions for each utility are shown in **Figure 30**. The GHG Calculator shows the annual emissions to 2020. For this analysis, the emissions after 2020 were assumed to continue to decrease for the four highest emitters and to remain constant for the three lowest emitters (PG&E, SDG&E, and SMUD).

Figure 30: GHG Emissions Rate by Utility



Source: GHG Calculator V3c to 2020, ICF Assumptions 2021-2030.

For the Cap-and-Trade Program not to adversely affect California electricity consumers, the electric utilities will be required to use their auction revenues to reimburse customers for added electricity costs. The exact mechanism for this reimbursement was not finalized as of December 2011. For this analysis it was assumed that 90 percent of the resulting increase in electric rates would be reimbursed to customers.

The added cost to average electricity rates are based on the credit price, the assumed GHG emissions content of average power production, and the reimbursement percentage. Table 46 shows the net effect on electric rates due to cap and trade both before and after reimbursement. The calculated effect on electric prices before reimbursement ranges from 3 to 11 mills/kWh depending on utility and period. After reimbursement, the costs range from 0.3 to 1.1 mills/kWh. The cap-and-trade increases and the RPS increases are additive.

Table 46: Effect of Cap and Trade on Average Retail Electric Rates

Electric Price, $/kWh	2011-2015	2016-2020	2021-2025	2026-2030
Cap and Trade With No Electric Ratepayer Reimbursement				
LADWP	$0.0075	$0.0083	$0.0099	$0.0112
Other North	$0.0057	$0.0065	$0.0078	$0.0089
Other South	$0.0062	$0.0069	$0.0082	$0.0094
PG&E	$0.0030	$0.0030	$0.0037	$0.0045
SCE	$0.0041	$0.0045	$0.0054	$0.0061
SDG&E	$0.0040	$0.0039	$0.0049	$0.0058
SMUD	$0.0034	$0.0036	$0.0045	$0.0054
Cap and Trade With 90% Electric Ratepayer Reimbursement				
LADWP	$0.0006	$0.0013	$0.0017	$0.0019
Other North	$0.0005	$0.0010	$0.0013	$0.0015
Other South	$0.0005	$0.0011	$0.0014	$0.0016
PG&E	$0.0003	$0.0005	$0.0006	$0.0007
SCE	$0.0003	$0.0007	$0.0009	$0.0010
SDG&E	$0.0003	$0.0006	$0.0008	$0.0010
SMUD	$0.0003	$0.0006	$0.0008	$0.0009

Source: ICF International, Inc.

The effect on CHP fuel costs is based on the carbon content of natural gas — 117 lb/MMBtu. The cost increase for incremental natural gas consumption by CHP producers is shown in **Table 47**.

Table 47: Impact of Cap and Trade on Natural Gas Price

	2011-2015	2016-2020	2021-2025	2026-2030
Natural Gas Price Adders, 2011 $/MMBtu	$0.67	$1.70	$2.23	$2.65

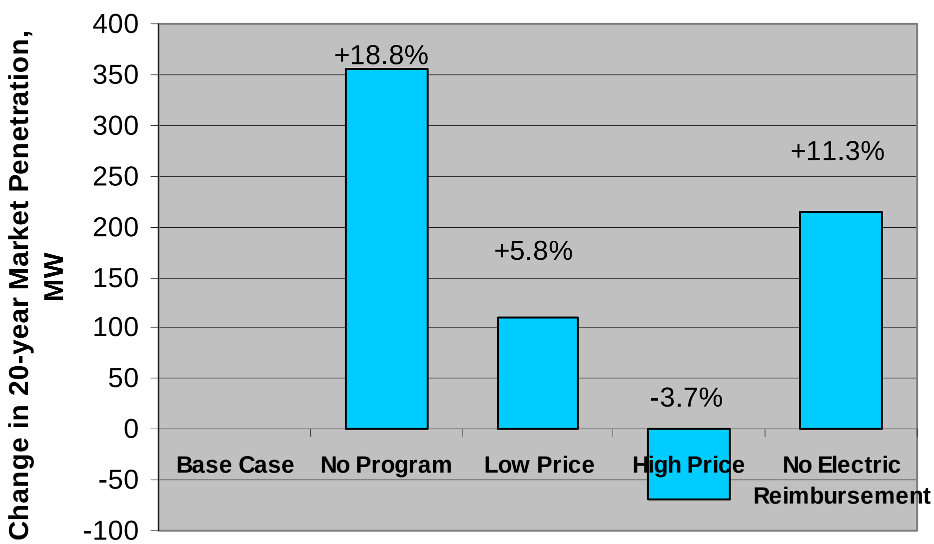
Source: ICF International, Inc.

While the increase in electric prices stimulates CHP development, the increase in gas prices reduces it. The overall effect is negative. In addition, the increase in regulatory exposure for potential CHP power producers would likely be an inhibiting factor in future project development.

Base Case Sensitivity to Cap-and-Trade Allowance Cost Assumptions

There is uncertainty about what the market clearing prices for the CO_2 allowances will be and how those prices will affect the market. The team evaluated the sensitivity of CHP market penetration results under the Base Case. The market changes are shown in **Figure 31**. With no cap-and-trade program, market penetration over the next 20 years would be 18.8 percent higher. The low and high price tracks shown in **Figure 29** would increase market penetration by 5.8 percent for the low price track and reduce market penetration by 3.7 percent for the high price track. Under the Base Case medium price track assumption but without reimbursement of costs to electric ratepayers, market penetration for CHP would increase by 11.3 percent.

Figure 31: Effect of CO_2 Allowance Price on Market Penetration Compared to the Base Case



Source: ICF International, Inc.

High Case Cap and Trade Assumptions

For the High Case, it was assumed that the allowance costs due to incremental CHP gas consumption would be reimbursed on a 100 percent basis.

Self-Generation Incentive Program

Base Case SGIP Assumptions

The details of the SGIP program are described in detail in Chapter 2. The program consists of the following aspects:

- A capital cost credit for CHP technology that is awarded 50 percent up front and 50 percent over five years, based on system performance. Fuel cells are eligible for \$2,250/kW in total payments; other CHP technologies are eligible for \$500/kW in total payments.
- There is no CHP project size limit, but the incentives are paid on a declining basis — 100 percent for the first MW, 50 percent for the second MW, and 25 percent for the third MW.
- There are programmed reductions in payments after 2013 amounting to a 5 percent reduction per year for conventional technologies and 10 percent per year for emerging technologies (fuel cells.)

The current authorization expires in January 2016. There is no guarantee that the program will be continued. The Base Case assumption for SGIP is that the program is simply allowed to expire after January 2016. The yearly performance payments were modeled based as a present value incentive at a 10 percent discount rate. High load factor CHP was assumed to receive the full value of the incentive payments; for low load factor applications, the performance incentives were discounted. The additional 20 percent California manufacturer's incentive was not included in the analysis.

Medium Case SGIP Assumptions

For the Medium Case scenario, it was assumed that the SGIP program would be continued beyond 2016 with the same terms and requirements as the current program. For this analysis, it was assumed that the 10 percent reduction in payments for fuel cells would drop to 5 percent when the dollar value of the incentive equals the payment for conventional technologies. For the High Case, it was assumed that there would be no reduction in payments for conventional CHP, and that emerging CHP would be phased downward until it was equal to the conventional payment and then both would decline until the incentive dropped to zero.

High Case SGIP Assumptions

The High Case SGIP assumption was that the program would be legislatively extended indefinitely with no reduction in incentive payments. The effective payment percentages for all three scenarios are shown in **Table 48**.

Table 48: Share of Current SGIP Incentives by Scenario

Share of Current SGIP Payments	2011-2015	2016-2020	2021-2025	2026-2030
Base Case — Phased Reduction, Hard Stop 2016				
Conventional Value	97.0%	0.0%	0.0%	0.0%
Emerging Value	94.0%	0.0%	0.0%	0.0%
Medium Case — Phased Reduction				
Conventional Value	97.0%	75.0%	50.0%	25.0%
Emerging Value	94.0%	50.0%	15.8%	5.6%
High Case — No Reduction in Conventional				
Conventional Value	100.0%	100.0%	100.0%	100.0%
Emerging Value	97.0%	75.0%	50.0%	25.0%

Source: ICF International, Inc.

CHP Power Export Pricing and Market Response

All Cases – AB-1613 for Systems Less Than 20 MW

All scenarios use the calculated AB 1613 export FIT for CHP systems with capacities less than 20 MW described in Section 2 and shown in **Table 49**.

Table 49: AB 1613 Export Price Estimates

AB 1613 Export Prices	2011-2015	2016-2020	2021-2025	2026-2030
AB 1613 FIT Basis	$0.0611	$0.0631	$0.0691	$0.0739
50-500 kW	$0.0611	$0.0631	$0.0691	$0.0739
500-1,000 kW	$0.0611	$0.0631	$0.0691	$0.0739
1-5 MW	$0.0605	$0.0624	$0.0685	$0.0732
5-20 MW	$0.0605	$0.0624	$0.0685	$0.0732
>20 MW	$0.0610	$0.0630	$0.0690	$0.0738

Source: ICF International, Inc.

Base Case –SRAC for Systems Greater Than 20 MW

Assumptions regarding large system export are based on SRAC and MPR. However, these administratively derived prices are intended to reflect an estimate of market pricing that would occur under future CHP procurement programs.

For the Base Case, it was assumed that CHP systems larger than 20 MW that are not eligible for the AB 1613 FIT would receive the SRAC payment for exported power. Under the *QF*

Settlement, the SRAC energy price is applicable to transition PPAs, legacy PPAs, QF PPAs, and as-available PPAs.

The SRAC includes capacity payment that is heavily weighted to on-peak delivery and an energy calculation based on the cost of delivered gas generating power at an incremental energy rate that is specified administratively through 2014 and then defined by the market heat rate thereafter.[68] The SRAC energy payments have time-of-day multipliers, but, like the AB 1613 factors, they average to one for constant rate of export throughout the year. For the gas prices used in this analysis, the SRAC for a constant continuous rate of power delivery is shown in **Table 50**.

Table 50: Continuous Delivery Average SRAC

	>20 MW CHP Gas Price				>20 MW SRAC $/kWh			
Utility	**2011-2015**	**2016-2020**	**2021-2025**	**2026-2030**	**2011-2015**	**2016-2020**	**2021-2025**	**2026-2030**
LADWP	$5.24	$5.55	$6.34	$7.06	$0.050	$0.049	$0.055	$0.059
SCE	$5.24	$5.55	$6.34	$7.06	$0.050	$0.049	$0.055	$0.059
SDG&E	$5.35	$5.66	$6.44	$7.16	$0.050	$0.050	$0.055	$0.060
Other South	$5.24	$5.55	$6.34	$7.06	$0.050	$0.049	$0.055	$0.059
PG&E	$4.95	$5.26	$6.04	$6.76	$0.047	$0.047	$0.052	$0.057
SMUD	$4.95	$5.26	$6.04	$6.76	$0.047	$0.047	$0.052	$0.057
Other North	$4.95	$5.26	$6.04	$6.76	$0.047	$0.047	$0.052	$0.057
Average Heat Rate, Btu/kWh	7,944	7,458	7,358	7,267				

Source: Analysis of 2012 SRAC tariffs.

Medium Case — Modified MPR (>20 MW) With Strong Market Response

SRAC pricing does not provide much stimulus for CHP export. For the Medium Case, large export pricing was estimated based on adaptation of the *2011 Draft Market Price Referent (2011 Draft MPR)* to the gas price forecast used in this analysis. In addition, a strong market response rate was used for large export projects.

The *2011 Draft MPR* calculation is based on the avoided cost of a new gas-fired, combined cycle power plant as shown in **Table 51**. In addition, the MPR includes the value of avoided GHG emissions. For this analysis, the assumption used was the cap-and-trade credit price forecast previously described.

68 Based on analysis of PG&E, SDG&E, and SCE Short Run Avoided Cost Energy Price Update for Qualifying Facilities, Effective January 1-January 31, 2012.

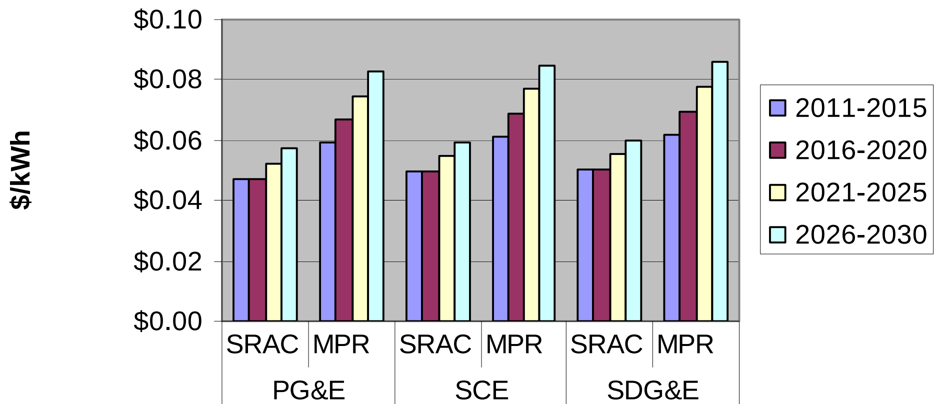
Table 51: *2011 Draft MPR* Reference Combined Cycle Power Plant

Capacity, MW	**500**
Installed Capital Costs (2011 $/kW)	$1,136
Heat Rate, Btu/kWh	6,879
Capacity Factor	91.77%
Fixed O&M, $/kW-yr	8.83
Variable O&M, mills/kWh	$3.11
Capital Fixed Charge Rate	11.66%
20-year WACC	7.57%
Taxes and Insurance %	1.80%

Source: CPUC, first year plant performance.

Figure 32 compares the large export pricing used in the Base Case (SRAC) with the pricing assumptions for the Medium and High Cases (MPR).

Figure 32: Comparison of SRAC and MPR Export Pricing for Large CHP

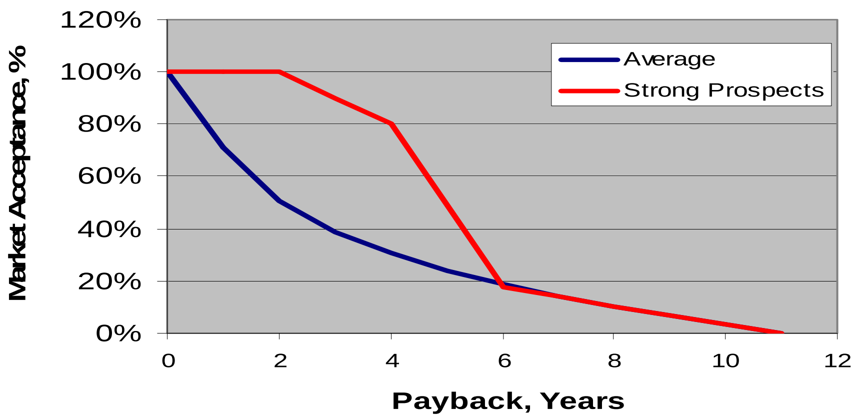


	PG&E SRAC	PG&E MPR	SCE SRAC	SCE MPR	SDG&E SRAC	SDG&E MPR
2011-2015	$0.047	$0.059	$0.049	$0.061	$0.050	$0.061
2016-2020	$0.047	$0.067	$0.049	$0.069	$0.050	$0.069
2021-2025	$0.052	$0.074	$0.054	$0.076	$0.055	$0.077
2026-2030	$0.057	$0.082	$0.059	$0.085	$0.060	$0.085

Source: ICF International, Inc.

It was further assumed that, with pricing issues for large CHP export resolved, there would be a perception of lower risk to go forward with projects. This lower risk is represented by the use of the strong market response curve for export projects larger than 5 MW. As described in Appendix A, the ICF CHP Market Model bases the economic market for CHP on the relationship between the project payback and the share of customers that would elect to go forward at that payback. More decision-makers would accept a lower payback than a higher payback. The relationship between payback and market acceptance was developed with surveys of California commercial and industrial facilities conducted by Primen as part of the 2005 CHP market assessment.[69] The average acceptance curve is used as the default market response curve for all markets and sizes. The market response attributed to strong prospects, those who were actively considering moving forward with CHP, was used in the Medium Case for export markets larger than 5 MW. The average and strong prospects market acceptance curves are shown in **Figure 33**.

Figure 33: Market Acceptance Curves



Source: Adapted from Primen.

High Case –Modified MPR (>20 MW) With Strong Market Response and Power Maximization

The High Export Case continues with the MPR pricing assumptions. However, it is assumed that utility ownership of CHP will increase the focus on power production. Therefore, in the high case assumptions, the export technical market potential for projects larger than 50 MW is assumed to use gas turbine combined cycle technology. This change, shown in **Table** 52, increases the electric capacity of projects in the larger than 20 MW size category from 3,567 to 5,401 MW — a more than 50 percent increase.

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

Table 52: Export CHP Potential – High Electric Focus by IOUs

Technical Potential Basis	Thermal Focus >20 MW	Electric Focus >20 MW
LADWP	240	592
PG&E	2,360	2,876
SCE	691	1,425
SDG&E	171	330
SMUD	0	0
Other North	106	195
Other South	0	0
Total	**3,567**	**5,419**

Source: ICF International.

Risk Perception and Market Response

In each size category analyzed in the model, not all of the technical market potential is included in the economic analysis. Maximum market participation (MMP) in each size category is restricted to reflect the effects of customers not considering CHP or being unable to use CHP for reasons of perceived risk, lack of financing, business instability, specific site restrictions, and other factors. As the market conditions become more favorable, the MMPs are raised proportionally with the increase in market to reflect the better business environment and the greater willingness to participate in project development. **Table 53** shows the MMP factors used for each of the three market scenarios. While the application of this factor is judgmental, it is roughly tied to the change in the economic market calculation. Compared to the Base Case participation rates, the Medium Case has 20 percent higher participation in the smallest size category and 6 percent greater participation in the largest size category. The High Case increases participation rates, again compared to the Base Case, by 30 percent in the smallest category and 12 percent greater participation in the largest category.

Table 53: Maximum Market Participation Rates

Maximum Market Participation Rates	50-500 kW	500-1000 kW	1-5 MW	5-20 MW	>20 MW
Base Case	50%	60%	70%	80%	80%
Medium Case	60%	69%	77%	85%	85%
High Case	65%	70%	79%	90%	90%

Source: ICF International, Inc.

Additional High Case Measures

Standby Power Cost Mitigation

For the High Case, it is assumed that IOU electric customers with CHP receive relief from nonbypassable charges (NBCs) and that CHP customers paying a reservation demand charge should not also have to pay additional demand charges for outages of the CHP system.

Currently, CHP customers that reduce their consumption as a result of CHP power production must still pay the Public Purpose Program Charges, Nuclear Decommissioning, and DWR Bond Charges on all the power that they both consume and produce. Customers that reduce their consumption due to the installation of energy efficiency measures do not have to pay these charges on their avoided consumption.

In addition, all three major IOUs charge a reservation demand charge for CHP customers that reflects the costs of being ready to serve the customer if the CHP system has an outage. SDG&E and SCE also charge the CHP customer full demand charges during a CHP system outage. PG&E does not impose these additional demand charges but does charge higher energy rates. For this case, it was assumed that only the reservation demand charges are applied to the CHP capacity and not additional demand charges, which should be covered under the reservation charge.

These changes are applied to the IOU electric territories only. The combined effect is to increase the CHP average avoidable rate by 1–2 cents/kWh.

10 Percent California State Investment Tax Credit for CHP

For the High Case, a 10 percent California investment tax credit is applied to CHP investments with no time limit or size restriction. The 10 percent ITC effectively reduces CHP capital costs by 6.5 percent — as the state ITC is partially offset by an increase in federal taxes since state taxes are deductible from income in the calculation of federal taxes owed.

CHP Capital Cost Reduction

As previously stated, the High Case includes an additional 10 percent reduction in capital costs by the end of the forecast period (2030). This reduction reflects additional technology improvement and more competitive pricing as a result of the larger market penetration.

Assumptions Related to Risk Perception in the CHP Market

The decision to invest in CHP is influenced by the customer’s perception of risk. In an effort to judgmentally represent the effect of risk in the different scenarios, the allowable maximum market participation in each size bin is restricted to reflect the effects of customers not considering CHP or being unable to use CHP for reasons of perceived risk such as lack of financing, business instability, specific site restrictions, and other factors. As the market increases, the maximum market participation factors are raised proportionally with the increase in market to reflect the better business environment and the greater willingness to participate. These assumptions are shown in **Table 54**.

Table 54: Modification of Market Participation Rates to Reflect Risk Perception

Maximum Market Participation Rates	50-500 kW	500-1,000 kW	1-5 MW	5-20 MW	>20 MW
Base Case	50%	60%	70%	80%	80%
Medium Case	60%	69%	77%	85%	85%
High Case	65%	70%	79%	90%	90%

Source: ICF International, Inc.

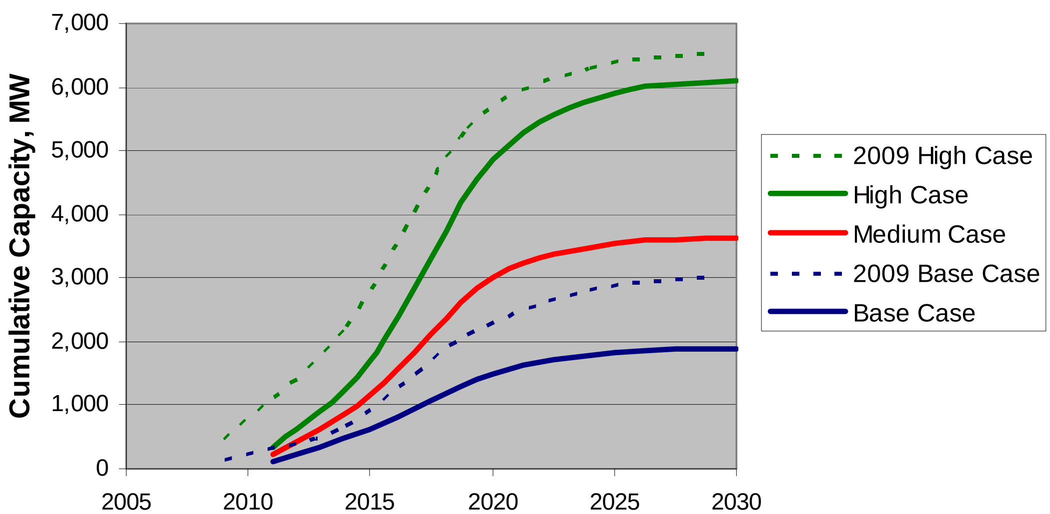
Scenario Results

This section presents the results for the base, medium, and high CHP market cases described.

Market Penetration and Energy Output

Cumulative market penetration for new CHP capacity for the three scenarios is shown in **Figure 34** and **Table 55**. The Base Case reflects the continuation of current policies in California. The Medium and High Cases show the added CHP market penetration that can be achieved with the additional policy measures described in the previous section. The 2011 20-year cumulative CHP market penetration ranges from 1,888 MW in the Base Case to 6,108 MW in the High Case. The figure and table also compare the 2011 scenario forecast with the Base and High Cases from the 2009 CHP market assessment.

Figure 34: Cumulative Market Penetration by Scenario



Source: ICF International, Inc.

Table 55: Cumulative Market Penetration by Scenario

2011 Scenarios	Cumulative New CHP Market Penetration, MW				
	2011	2015	2020	2025	2030
Base Case	123	617	1,499	1,817	1,888
Medium Case	233	1,165	3,013	3,533	3,629
High Case	340	1,700	4,865	5,894	6,108
2009 Scenarios	**Cumulative New CHP Market Penetration, MW**				
	2009	**2014**	**2019**	**2024**	**2029**
Base Case	136	680	2,096	2,816	2,998
High Case (All-in)	442	2,209	5,338	6,306	6,519

Source: ICF International, Inc.

The 2011 market scenarios, in general, show lower cumulative market penetration than the 2009 scenarios. There are a number of contributing factors:

- The economic slowdown has reduced technical market potential.
- There are fewer existing businesses in California with CHP potential, and the growth expectations for those markets over the next 20 years are also lower.
- CHP technology capital costs have increased due to higher equipment and installation costs.
- Export pricing for AB 1613 eligible projects had not been developed in 2009, so the 2009 analysis was based on the renewable FIT, which includes a significant component related to avoidance of GHG emissions. The CHP FIT as developed is much lower than in 2009.
- The difference between gas and electric prices, spark spread, is somewhat more favorable now than in 2009, but this is offset by the effects of cap and trade on natural gas prices.
- Cap and trade was not included in the 2009 assumptions.
- The SGIP program is more inclusive than in 2009, but the stimulation of market penetration in the Base Case is limited by the program's current expiration date of 2016.

Table 56 shows detailed results for 2030, the end year of the market forecast. The table shows the installed CHP capacity, electricity generated and avoided through thermally activated air conditioning, the required fuel consumption, and the net investment and state incentives. The industrial and commercial markets are roughly evenly split in the Base Case. In the Medium and High Cases industrial CHP market penetration is about twice the size of growth in the commercial sector due to large additions to the export market in the medium and high cases. The electricity generation from CHP capacity, including avoided air conditioning, ranges from 12 billion to 42 billion kWh/year – base and high cases, respectively. This reflects an average load factor of 74 percent in the Base Case and 79 percent in the High Case. With conservative estimates in the model regarding use of thermal energy ranging from 80-100 percent, depending on the market, the average incremental heat rate for this produced power is around 6,000 Btu/kWh.

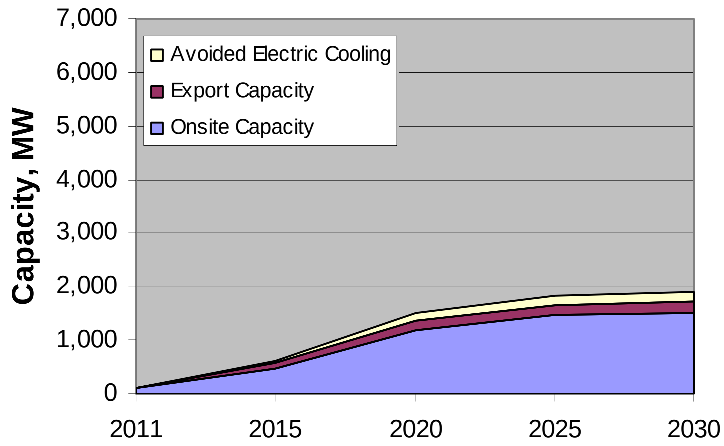
Table 56: Scenario Capacity and Energy Impacts by 2030

Scenario	Base	Medium	High
Cumulative Market Penetration, MW			
Industrial	845	2,400	3,739
Commercial/Institutional	851	1,001	1,918
Residential	32	42	91
Cumulative Market Penetration	1728	3443	5747
Avoided Electric Cooling	160	186	361
Scenario Grand Total	**1,888**	**3,629**	**6,108**
Annual Electric Energy, Million kWh/yr			
Industrial	6,283	18,716	28,925
Commercial/Institutional	5,313	6,180	11,594
Residential	226	293	635
Total	**11821**	**25189**	**41154**
Avoided Cooling	496	571	1074
Scenario Grand Total	12,317	25,760	42,228
Annual Natural Gas Use, Billion Btu/year			
CHP Fuel	113,891	236,124	370,599
Less Avoided Boiler Fuel	37,368	88,081	111,975
Incremental Onsite Fuel (billion Btu/year)	76,523	148,043	258,623
Investment Requirements, Million 2011 $			
Cumulative Investment (Million 2011 $)	$3,081	$5,301	$7,025
Cumulative Capital Incentives(Million 2011 $)	$76	$272	$1,609

Source: ICF International, Inc.

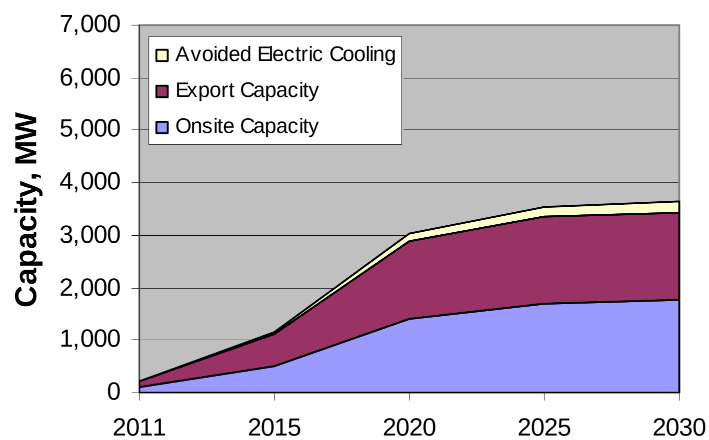
Figure 35, **Figure 36**, and **Figure 37** show the cumulative market penetration growth for the three scenarios by market type: on-site CHP, export, and avoided air-conditioning capacity. In the Base Case, 80 percent of the market penetration is in on-site applications and only 11 percent in export. In the Medium and High Cases the export shares are much increased, from 40 – 46 percent of the total market, due to the increased stimulus for export in those cases. Avoided air conditioning is a fairly consistent 10 – 11 percent of the on-site capacity in all cases.

Figure 35: Base Case Cumulative Market Penetration by Type



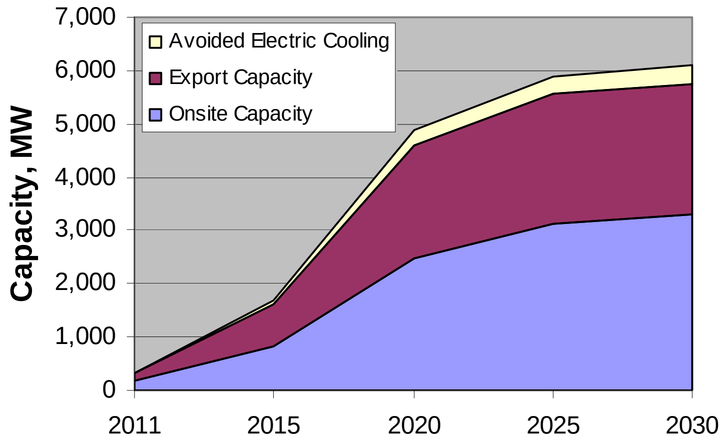
Source: ICF International, Inc.

Figure 36: Medium Case Cumulative Market Penetration by Type



Source: ICF International, Inc.

Figure 37: High Case Cumulative Market Penetration by Type

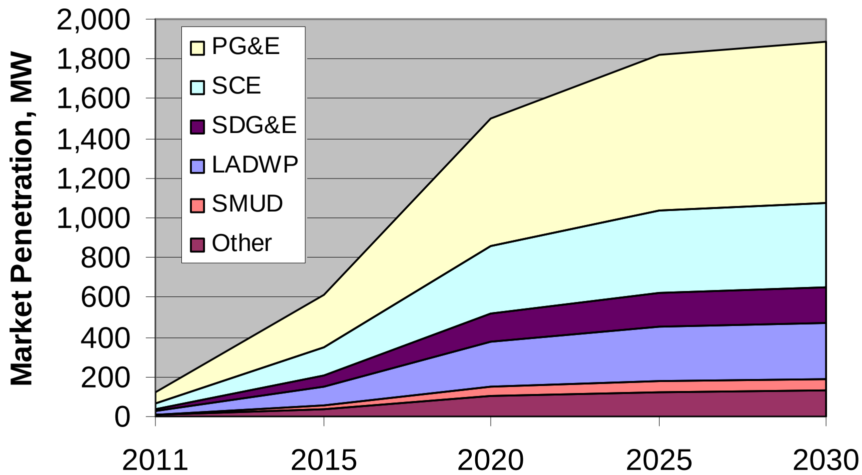


Source: ICF International, Inc.

The breakdown of Base Case market penetration by utility region is shown in **Figure 38**. The market penetration shares are as follows:

- PG&E – 43 percent
- SCE – 22 percent
- LADWP – 15 percent
- SDG&E – 10 percent
- SMUD – 3 percent
- Other – 7 percent

Figure 38: Base Case Cumulative Market Penetration by Utility Region



Source: ICF International, Inc.

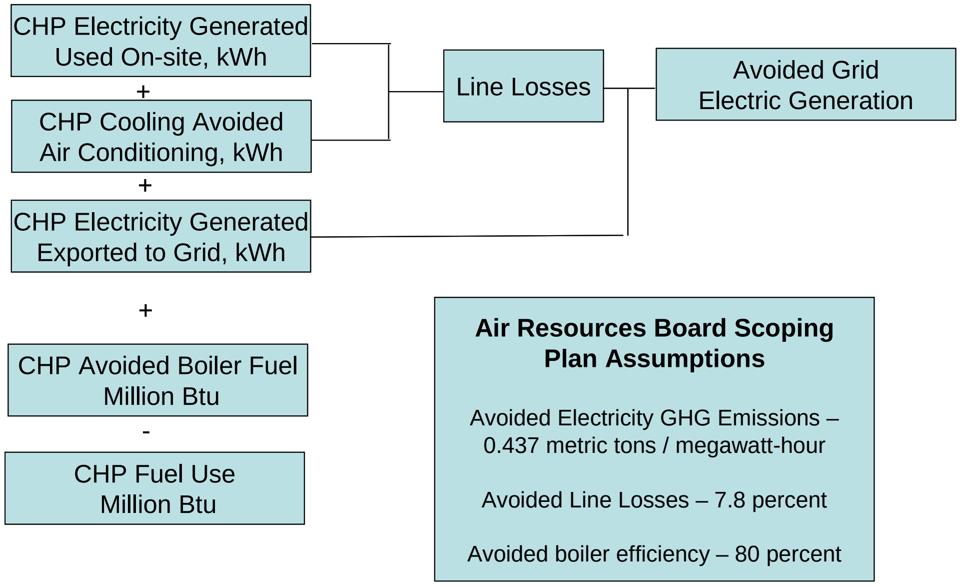
Detailed results by utility region are included in Appendix D.

Greenhouse Gas Emissions Savings

The contribution of combined heat and power to statewide reductions in greenhouse gas emissions is the principal motivation for this market assessment and identification of policy measures that will increase CHP market penetration.

To provide an estimate that could be compared to the ARB *Scoping Plan*, the team used the ARB assumptions for avoided emissions as shown in **Figure 39**. The ARB assumptions for avoided generation emissions, electric line losses, and avoided boiler efficiency were used as shown in the figure. The electric and thermal performances of the combined heat and power systems were taken from the multisector outputs of the ICF CHP Market Model. Each market sector has its own performance and output factors.

Figure 39: Estimation Procedure for Greenhouse Gas Emissions Reduction From CHP



Source: ICF International, Inc.

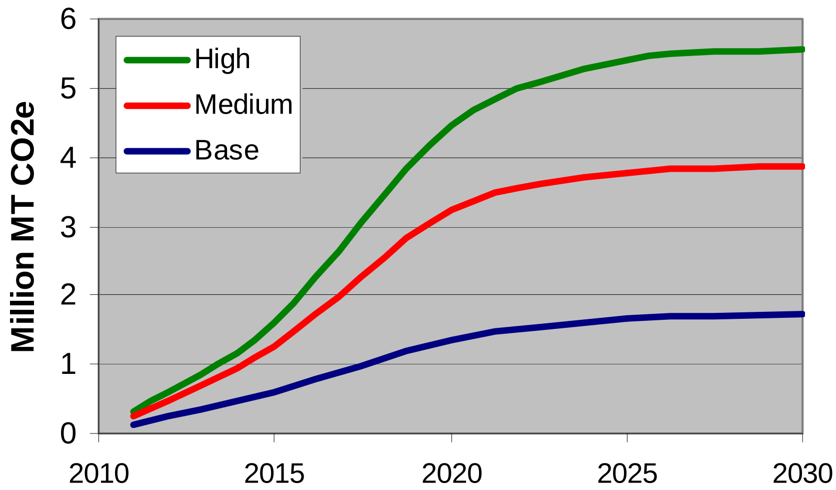
The GHG emissions from CHP are summed from the market model outputs by size, application, and technology as a function of the incremental fuel use calculated as follows:

Incremental CHP Fuel Use = EG x (HR – TUF x AT / BE)

EG = Electricity Generated, kWh
HR = Heat Rate, Btu/kWh (higher heating value)
TUF = Thermal Utilization Factor
AT = Available Thermal Energy, Btu/kWh
BE = Boiler Efficiency

Calculated on this basis, the avoided annual GHG emissions range from 1.4 to 4.5 MMT in 2020 and 1.7 to 5.6 MMT by 2030, as shown in **Figure 40**.

Figure 40: Greenhouse Gas Emissions Reduction From CHP Compared to Current Emissions

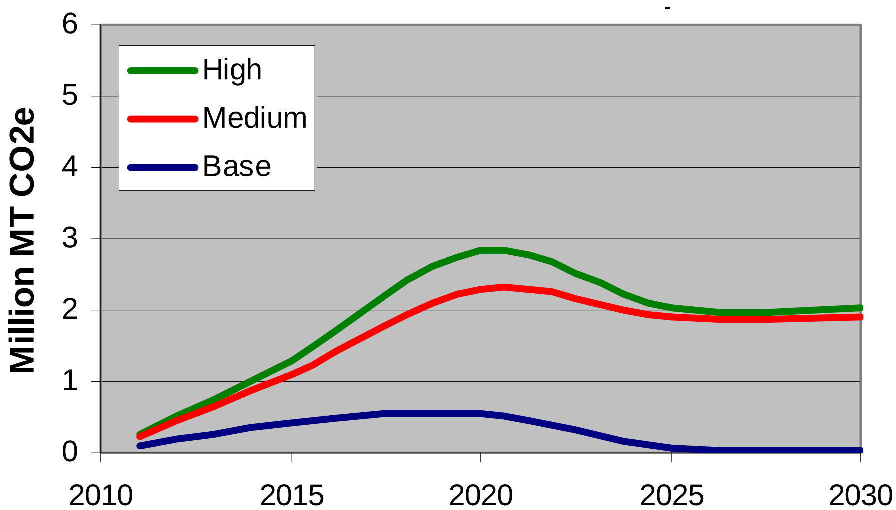


Source: ICF International, Inc.

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

Figure 41 shows the valuation of greenhouse gas emissions savings over time with the RPS in place. Medium and High Case reductions are less than the Base Case because, as noted, export market penetration does not reduce the GHG emissions savings. The export market is much higher in the Medium and High Cases.

Figure 41: Greenhouse Gas Emissions Savings From Combined Heat and Power With 33 Percent Renewables Portfolio Standard



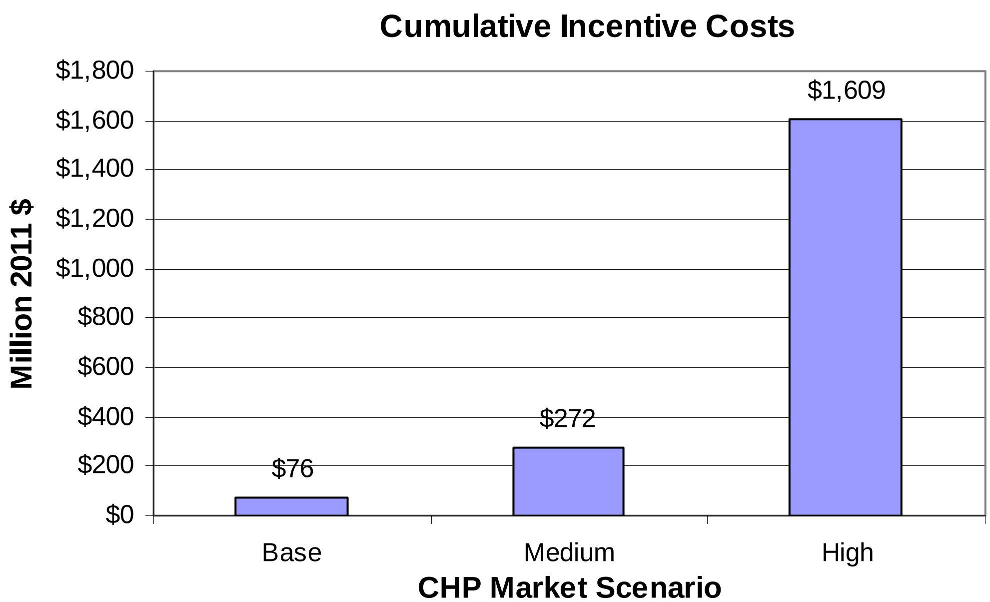
Source: ICF International, Inc.

Incentive Costs

Figure 42 shows the cumulative California state incentive costs covering SGIP and the proposed state investment tax credit for each scenario.

- The Base Case incentive cost is $76 million (2011 $) to cover the cost of the SGIP program until it is discontinued after 2016.
- The Medium Case incentive cost is $272 million (2011 $) to cover the cost of the SGIP program with the phased reduction extending throughout the 20-year forecast period.
- The High Case incentive cost is $1.6 billion (2011 $) to cover the cost of the SGIP program with no reduction for conventional CHP technologies and a 10 percent investment tax credit for CHP investment.

Figure 42: Cumulative State Incentive Costs



Source: ICF International, Inc.

CHAPTER 4: Conclusions

The Base Case results show that, under the current policy landscape, CHP will fall well short of the ARB *Scoping Plan* market penetration target. Additional policy measures, represented in the Medium and High Cases, are needed to raise market penetration up to the *Scoping Plan* target.

As noted, this report shows lower cumulative market penetration than the 2009 *Combined Heat and Power Market Assessment* due to the following factors:

- Reduced economic activity
- Higher CHP system installed costs
- Lower assumed export pricing under AB 1613
- Effective increases to natural gas costs resulting from the cost of allowances under cap and trade
- Early ending or phased reduction of incentives under the Self-Generation Incentive Program

The markets for large and small combined heat and power systems have different needs and respond to different types of incentives. **Table 57** provides the breakdown of 20-year cumulative market penetration by scenario for large (greater than 20 megawatts) and small (less than 20 megawatts) systems.

Table 57: Cumulative Market Penetration by Market for Large and Small Systems

Scenario	Base		Medium		High	
Size	< 20 MW	> 20 MW	< 20 MW	> 20 MW	< 20 MW	> 20 MW
On-Site	1,269	246	1,519	263	2,901	388
Avoided Air Conditioning	130	30	155	32	316	45
Export	91	122	93	1,568	295	2,162
Total	**1,489**	**399**	**1,766**	**1,863**	**3,513**	**2,595**

Source: ICF International, Inc.

Small capacity markets respond to the SGIP, transmission and distribution deferral payments, electric rate increases caused by implementation of the RPS, and CHP system cost reductions over time as the market matures. Large capacity markets respond mainly to the export price. All markets benefit from investment tax credits. Small markets, primarily, are negatively affected by costs associated with cap and trade; large export markets can recover these costs in their contracts or pass them on to the utility.

Table 57 also shows how important stimulation of the export market is to achieving the high levels of market penetration forecast under the Medium and High Cases. In the Base Case, the export market additions of new CHP are only 213 MW. In the High Case with higher pricing signals, the market growth increases to 2,457 MW. Prices approaching the full long-run marginal cost of power are needed for significant penetration of new large CHP export projects – not short-run avoided cost. Smaller, AB 1613-eligible projects have higher costs, making it difficult to compete even with the utility long-run marginal cost provided.

The export analysis in this project was based on setting the price for export and letting the market model solve for the quantity of market penetration. Under the *QF Settlement* and the Long Term Procurement Planning Process, the utilities set the quantity of export combined heat and power desired, and the price is determined by a bidding process. The 3,000 MW procurement targets under the *QF Settlement* could be fully subscribed by existing combined heat and power systems – after the 3,000 MW target is met, new procurement targets will be determined in Long Term Procurement Planning Process. Therefore, achieving the levels of market penetration for new export CHP defined under the Medium and High Cases will depend on the targets for CHP capacity that are set.

The greenhouse gas emissions savings from CHP are smaller than the ARB scoping target of 6.7 MMT per year of carbon dioxide even in the High Case, where market penetration exceeds the ARB estimate. The reasons for this difference stem from the nature of the CHP markets themselves. In the *Scoping Plan* all the CHP market penetration was assumed to be high load factor systems with full thermal usage. In this analysis, thermal usage rates for the small markets were assumed to be only 80 percent. Larger markets were assumed to have 90 – 100 percent thermal usage. In addition, markets that use a portion of the available waste heat to replace electric air conditioning have much lower emissions savings than those that strictly replace boiler fuel. Low load factor markets also save less due to their reduced annual hours of operation.

Concurrent carbon reduction programs will reduce the marginal greenhouse gas savings over time as the California energy economy becomes less dependent on fossil fuels. However, this will be true for all measures in the *Scoping Plan*. The focus in comparing the efficacy of measures to reduce greenhouse gas emissions should be on cost-effectiveness. Combined heat and power is less costly than some renewable energy sources providing equivalent emission reductions.

Finally, CHP saves money for the facilities that adopt it. This is the motivation that drives customer adoption. By 2030, CHP would save participating customers $740 million per year in energy costs under the Base Case and $2.9 billion per year under the High Case. Measures that provide a mechanism to bring societal benefits like greenhouse gas emissions reduction, transmission and distribution capacity deferral, and energy efficiency into the private investment decision will increase market penetration for CHP, as shown by the market response in the Medium and High Cases analyzed.

Acronyms

Acronym	Definition
2011 Draft MRP	*2011 Draft Market Price Referent*
AEO	*Annual Energy Outlook*
ARB	California Air Resources Board
Btu/kWh	British thermal unit per kilowatt hour
California SO	California Independent System Operator
CBECS	Commercial Buildings Energy Consumption Survey
CCC	California Cogeneration Council
CCHP	Combined cooling, heating, and power
CEPD	Commercial Energy Profile Database
CEUS	California Commercial End-Use Survey
CHP	Combined heat and power
CLECA	California Large Energy Consumers Association
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COP	Coefficient of Performance
CPUC	California Public Utilities Commission
CRS	Customer responsibility surcharges
D&B	Dun & Bradstreet
DG	Distributed generation
DL	Departing load
DOE	Department of Energy
DWR	Department of Water Resources
EG	Electricity Generation
EIA	Energy Information Administration
EIA *AEO 2011*	EIA *2011 Annual Energy Outlook*
Energy Commission	California Energy Commission
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EPUC	Energy Producers and Users Coalition and the Cogeneration Association of California
FERC	Federal Energy Regulatory Commission
FIT	Feed-in tariff
GHG	Greenhouse gas
GTI	Gas Technology Institute
HHV	Higher heating value
IOUs	Investor-owned utilities
ITC	Income tax credit
Kg/MWh	Kilogram per megawatt hour
kW	Kilowatt
kWh	Kilowatt hour
LADWP	Los Angeles Department of Water and Power
Lb/MWh	Pound per megawatt hour
LBNL	Lawrence Berkeley National Laboratory

Acronym	Definition
LHV	Lower heating value
LNG	Liquefied natural gas
MECS	Manufacturing Energy Consumption Survey
MIPD	Major Industrial Plant Database
MMBtu	Million British thermal units
MMP	Maximum market participation
MMT	Million metric tons
MPR	Market Price Referent
MT CO_2e	Metric ton carbon dioxide equivalent
MW	Megawatt
MWh	Megawatt hour
NAICS	North American Industry Classification System
NBC	Non-bypassable charges
NERC	Nuclear Energy Regulatory Commission
NO_x	Nitrogen oxides
Norton	Rita Norton & Associates
OIR	Order Instituting Rulemaking
O&M	Operation and maintenance
PBI	Performance-based incentive
P/H	Power-to-heat ratio
PG&E	Pacific Gas and Electric Company
PIER	Public Interest Energy Research
PPA	Power purchase agreement
PPA	Power Purchase Agreement
PPT	Pacific Prevailing Time
PURPA	Public Utility Regulatory Policies Act
QF	Qualifying facility
QFER	Quarterly Fuels Energy Report
RFO	Request for offers
RPS	Renewables Portfolio Standard
SCE	Southern California Edison
SCR	Selective catalytic reduction
SDG&E	San Diego Gas & Electric Company
SGIP	Self-Generation Incentive Program
SIC	Standard Industrial Classification
SMUD	Sacramento Municipal Utility District
SRAC	Short-run average cost
TOD	Time of day
$/kWh	Dollar per kilowatt hour

APPENDIX A: ICF 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 A-1**.

Table A-1: ICF CHP Market Model

Forecast Periods	2015, 2020, 2025, 2030
Market Segmentation: Application	High Load Factor
	Low Load Factor
	High Load Factor With Cooling
	Low Load Factor With Cooling
	Export
Market Segmentation: Size	50-500 kW
	500-1,000 kW
	1-5 MW
	5-20 MW
	>20 MW
Market Segmentation: Region	PG&E
	SCE
	SDG&E
	LADWP
	SMUD
	Other North
	Other South
Major Input Assumptions	Technical Market Potential
	Technology Cost and Performance
	Energy Prices
	Application Load Profile
Economic Calculation Engine	CHP Economic Savings by Market and Size
	Payback Comparison
Market Penetration Estimation	Market Acceptance Curve vs. Payback
	Market Penetration of Economic Market
Model Outputs	Cumulative Market penetration in MW
	Electric, thermal and avoided AC Outputs
	Emissions Impacts

Source: ICF International.

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 each size are defined in terms of the CHP operating load factor and the degree and type of thermal energy usage.

The CHP Technical Potential described in Section 2 by individual market NAICS 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 use 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 A-2**. 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 A-2: Electric Load, Thermal Utilization, and Technology Assumptions by Size Bin

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

Abbreviations

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

Source: ICF International.

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

The cumulative market penetration is forecast in five-year increments. For this analysis, the forecast periods are 2015, 2020, 2025, and 2030.

Market Model Input Assumptions

The major inputs to the ICF CHP Market Model are:

- 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 *Chapter 2.* This potential is analyzed application by application, but the results are combined into the five market sectors and seven utility regions described previously. Facilities of like load factor, size, and thermal characteristics are assumed to offer the same economic opportunity for CHP. A summary of the technical market potential is shown in **Table A-3.**

Table A-3: 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 Commercial and Industrial Facilities						
High Load Factor	728	387	1,084	818	385	3,402
Low Load Factor	160	11	7	0	0	179
High Load Factor Cooling	539	283	751	751	396	2,719
Low Load Factor Cooling	1,339	540	850	179	51	2,960
Export	0	0	286	901	3,567	4,754
Total	**2,765**	**1,221**	**2,978**	**2,648**	**4,399**	**14,012**
In New Commercial and Industrial Facilities						
High Load Factor	70	32	79	51	20	252
Low Load Factor	41	3	2	0	0	46
High Load Factor Cooling	125	57	168	112	51	512
Low Load Factor Cooling	295	129	203	43	13	682
Export	0	0	9	40	131	180
Total	**531**	**220**	**461**	**245**	**214**	**1,671**

Source: ICF International.

CHP Technology Cost and Performance

The individual technologies that compete for market share within the economic calculation in the model were summarized in **Table A-2** and described in detail in Section 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 Chapter 2 by the capital cost multipliers shown in **Table A-4.**
- 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.
- SGIP and other state incentives are applied as described in the scenario analysis.

Table A-4: Capital Cost Multipliers

Utility	Cost Adder
LADWP	103.8%
Other North	105.8%
Other South	103.8%
PG&E	109.2%
SCE	103.8%
SDG&E	102.9%
SMUD	105.8%

Source: Means Online Quick Cost Estimator adjusted to one half of total project cost.

Energy Prices

The ICF CHP Model focuses on natural gas fired CHP markets. For each market segment defined by size and load factor, a CHP electric savings rate is estimated based on the avoided electric costs from operating a CHP system. Natural gas rates for CHP fuel and avoided fuel are also estimated. The basic assumptions are described in *Section 2*. Price changes resulting from the 33 percent RPS and cap and trade are described in the scenario assumptions.

Application Profiles

As shown in **Table A-2**, each CHP application is described in terms of its electric load factor and degree and type of thermal usage. These profiles determine the CHP electric and thermal outputs and the economic savings.

Economic Competitiveness of CHP and Market Acceptance

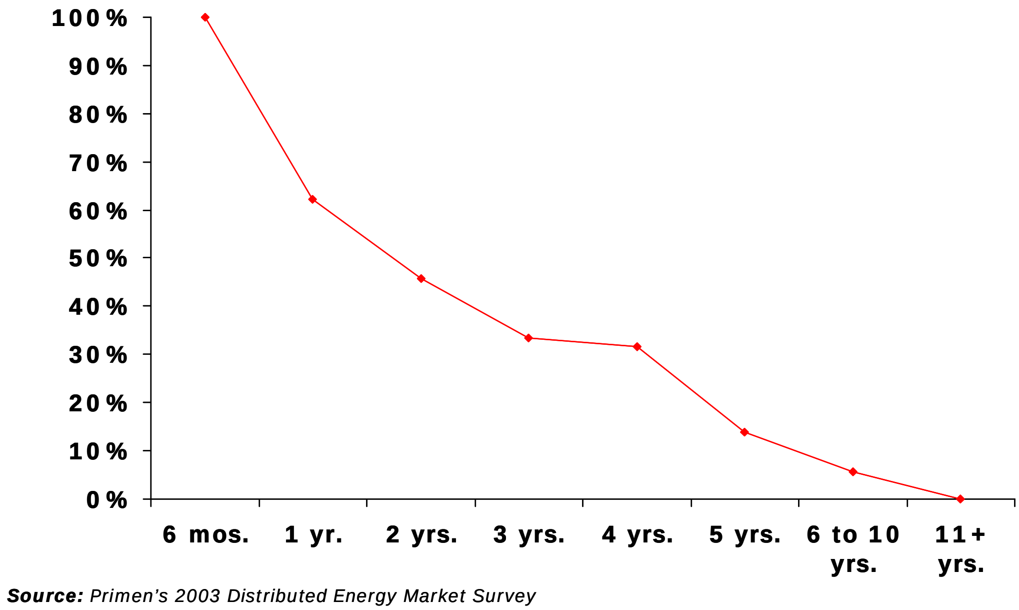
The economic competitiveness calculation within the ICF CHP Market Model is a simple payback calculation. The annual cost of operating the CHP system is compared to the avoided thermal and electric energy cost savings, allowing the number of years it would take for this annual savings to repay the initial 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 noncooling 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 used, 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 A-1** shows the percentage of the market that would accept a given payback period and move forward with a CHP investment based on survey results. As can be seen from the figure, more than 30 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 a return on investment (ROI) of between 49 – 100 percent.

Figure A-1: Share of the California Customers That Will Accept a Given Payback for a Proposed CHP Project



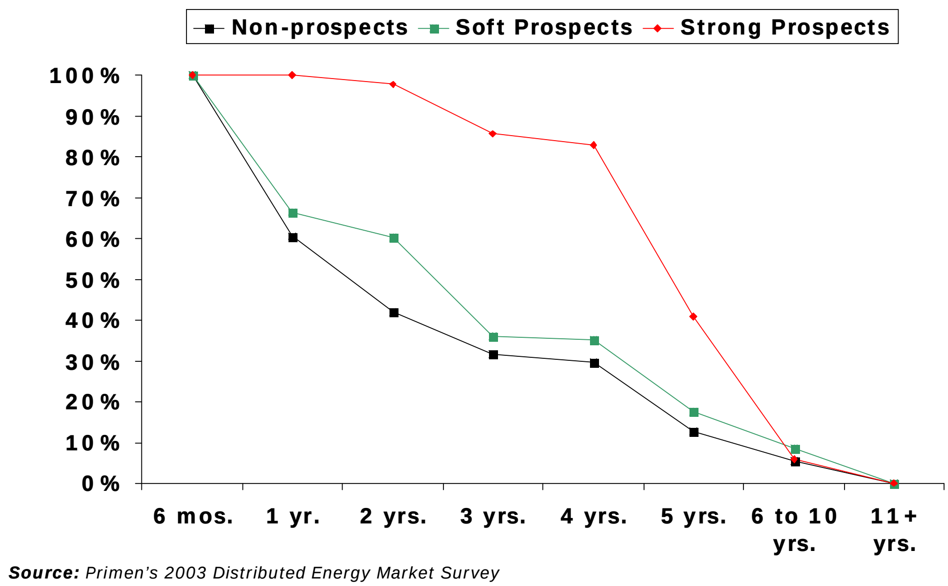
Source: Primen's *2003 Distributed Energy Market Survey.*

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

Potential explanations for rejecting a project with such high returns is that the average customer does not believe that the results are real and is protecting himself from this perceived risk by requiring very high projected returns before a project would be accepted, or that the facility is very capital limited and is rationing its capital raising capability for higher priority projects (market expansion, product improvement, and so forth.). 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.

It is also recognized that large potential CHP exporters are a great deal more sophisticated than the average facility operator and also may be more committed to making economic energy investments. For these customers, a different acceptance curve was used based on the earlier survey work. This curve was for survey respondents characterized as s*trong prospects*. Strong prospects, those that said they were actively evaluating on-site generation options and were more than 50 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 four years, but acceptance begins to drop rapidly once paybacks reach five years. **Figure A-2** shows the market acceptance curve for strong prospects that was used to define the market acceptance for the large export market.

Figure A-2: Market Acceptance of Different Payback Periods by Customer Interest in CHP



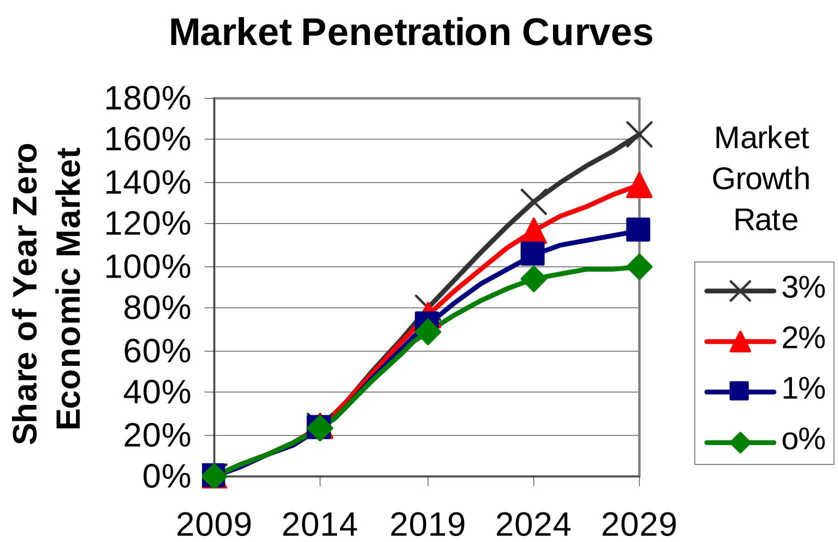
Source: Primen's *2003 Distributed Energy Market Survey*.

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

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

Figure A-3 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.

Figure A-3: Bass Diffusion Curves for 50 – 500 kW Market for a Range of Market Growth Rates



Source: ICF International.

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 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.

APPENDIX B: Existing CHP Detailed Tables

Table B-1: Existing CHP Operating in 2011 by Application and Fuel Type

		Biomass		**Coal**		**Natural Gas**		**Waste**		**Other**		**Total**	
	Application	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
Industrial	SIC 20: Food	2	20.7	2	62.5	56	1,377.3	2	3.6	3	3.6	65	1,467.7
	SIC 22: Textile Products					3	1.8					3	1.8
	SIC 24: Wood Products			1	44.0	2	51.0			12	181.3	15	276.3
	SIC 26: Paper					10	341.6			1	13.5	11	355.1
	SIC 27: Publishing					3	5.7					3	5.7
	SIC 28: Chemicals			1	108.0	15	93.2	5	72.7	1	1.9	22	275.8
	SIC 29: Petroleum Refining					11	847.5	7	370.4			18	1,217.9
	SIC 30: Rubber					1	0.5	1	27.0			2	27.5
	SIC 32: Stone, Clay, Glass					4	3.3					4	3.3
	SIC 33: Primary Metals					8	569.2					8	569.2
	SIC 34: Fabricated Metals					13	2.2					13	2.2
	SIC 36: Electrical Equipment					3	4.3			1	0.9	4	5.2
	SIC 37: Transportation Equip					3	13.1					3	13.1
	SIC 39: Misc Manufacturing					16	22.6	1	7.2			17	29.8
	Total Industrial	2	20.7	4	214.5	148	3,333.2	16.0	480.9	18.0	201.2	188	4,250.5
Other	SIC 9900: Unknown	28	13.2			207	100.4					235	113.6
	SIC 01: Agriculture	1	25.0			11	19.9					12	44.9
	SIC 02: Livestock	8	3.5			1	2.5					9	6.0
	SIC 13: Crude Oil			3	127.2	66	2,297.7	4	40.4	4	12.4	77	2,477.7
	SIC 14: Quarrying			1	55.0	2	100.4					3	155.4
	Total Other	37	41.7	4	182.2	287	2,520.9	4	40.4	4	12.4	336	2,797.6
		Biomass		**Coal**		**Natural Gas**		**Waste**		**Other**		**Total**	
	Application	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW	Sites	MW
Commercial	SIC 4200: Warehousing/ Cold Storage					5	158.5					5	158.5
	SIC 4500: Air Transportation					3	45.0			1	0.5	4	45.5
	SIC 4800: Communications					5	13.6					5	13.6
	SIC 4939: Utilities	2	5.8			10	86.2	1	17.0	2	0.5	15	109.5
	SIC 4952: Wastewater Treatment	41	100.0			9	88.3					50	188.3
	SIC 4953: Solid Waste Facilites	6	16.8					1	35.6			7	52.4
	SIC 4961: District Energy	1	1.3			2	9.1					3	10.4
	SIC 5000: Wholesale/Retail					2	0.8					2	0.8
	SIC 5411: Food Stores					6	1.4					6	1.4
	SIC 5812: Restaurants					5	0.1					5	0.1
	SIC 6512: Comm. Building					57	41.8					57	41.8
	SIC 6513: Apartments					24	1.7					24	1.7
	SIC 7011: Hotels					68	36.4					68	36.4
	SIC 7200: Laundries					56	1.1			2	0.03	58	1.2
	SIC 7990: Amusement/ Rec.					53	59.2					53	59.2
	SIC 8051: Nursing Homes					16	1.9					16	1.9
	SIC 8060: Hospital/Healthcare	1	1.0			49	165.3					50	166.3
	SIC 8211: Schools					115	10.3			1	0.1	116	10.3
	SIC 8220: Colleges/Univ.	1	0.4			51	295.0					52	295.4
	SIC 8300: Comm Services					2	1.9					2	1.9
	SIC 8400: Zoos/Museums					2	2.3					2	2.3
	SIC 8900: Services NEC					27	8.4			1	0.01	28	8.4
	SIC 9100: Government Fac.					23	52.4					23	52.4
	SIC 9200: Courts/Prisons					17	79.5					17	79.5
	SIC 9700: Military					10	130.8					10	130.8
	Total Commercial	52	125.2	0	0.0	617	1,290.8	2	52.6	7	1.1	678	1,469.8
	Grand Total	**91**	**187.6**	**8**	**396.7**	**1052**	**7,145.0**	**22**	**573.9**	**29**	**214.8**	**1,202**	**8,517.9**

Source: ICF International, Inc.

Table B-2: Existing CHP Operating in 2011 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	8	96.1	8	916.9	11	406.6	30	45.9	2	1.2	5	0.8	1	0.3	65	1,467.7
	SIC 22:Textile Products							3	1.8							3	1.8
	SIC 24:Wood Products	13	225.3	1	49.5			1	1.5							15	276.3
	SIC 26: Paper	1	13.5	2	69.0	7	268.6	1	4.0							11	355.1
	SIC 27: Publishing					1	3.0	2	2.7							3	5.7
	SIC 28: Chemicals	5	176.2	1	28.0	4	54.9	7	7.4			2	0.3	3	9.1	22	275.8
	SIC 29: Petroleum Refining	2	117.0	5	790.0	9	310.7					2	0.2			18	1,217.9
	SIC 30: Rubber	1	27.0					1	0.5							2	27.5
	SIC 32: Stone, Clay, Glass							4	3.3							4	3.3
	SIC 33: Primary Metals			1	567.0			5	1.4	1	0.6	1	0.1			8	569.2
	SIC 34: Fabricated Metals							11	1.8			2	0.4			13	2.2
	SIC 35: Machinery							2	1.1							2	1.1
	SIC 36: Electrical Equipment							3	5.1			1	0.1			4	5.2
	SIC 37: Transportation Equip	1	2.4			1	9.5	1	1.3							3	13.1
	SIC 38: Technical Instruments							1	1.0							1	1.0
	SIC 39: Misc Manufacturing					2	13.9	6	5.5	1	0.3	4	0.8	1	7.2	14	27.7
	Total Industrial	31	657.5	18	2,420.4	35	1,067.2	78	84.1	4	2.1	17	2.6	5	16.5	188	4,250.5
Other	SIC 9900: Unknown					2	2.4	158	96.0	6	3.5	69	11.7			235	113.6
	SIC 01: Agriculture	2	27.7	1	6.5	1	5.5	5	4.8			3	0.3			12	44.9
	SIC 02: Livestock							8	4.6	1	1.4					9	6.0
	SIC 13: Crude Oil	6	191.1	4	223.9	57	2,052.7	9	9.9			1	0.1			77	2,477.7
	SIC 14: Quarrying	1	55.0	1	55.4	1	45.0									3	155.4
	Total Other	9	273.8	6	285.8	61	2,105.6	180	115.3	7	4.9	73	12.1	0	0.0	336	2,797.6

		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
Commercial	SIC 4200: Warehousing/ Cold					3	157.0	2	1.5							5	158.5
	SIC 4500: Air Transportation			1	30.0	1	8.0	2	7.5							4	45.5
	SIC 4800: Communications					1	11.5	1	1.4			3	0.7			5	13.6
	SIC 4939: Utilities	1	17.0			4	76.6	9	15.8			1	0.1			15	109.5
	SIC 4952: Wastewater			1	28.0	4	83.7	20	67.6	9	6.6	16	2.4			50	188.3
	SIC 4953: Solid Waste Facilites	1	35.6					5	15.5			1	1.3			7	52.4
	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	2	0.6					6	1.4
	SIC 6512: Comm. Building					3	10.5	42	27.7	4	1.8	8	1.8			57	41.8
	SIC 6513: Apartments							21	1.3			3	0.4			24	1.7
	SIC 7011: Hotels					2	5.6	53	27.5	3	2.2	10	1.1			68	36.4
	SIC 7200: Laundries							58	1.2							58	1.2
	SIC 7990: Amusement/ Rec.			1	49.8	2	0.7	46	8.8			4	1.2			53	60.5
	SIC 8051: Nursing Homes							16	1.9							16	1.9
	SIC 8060: Hospital/Healthcare			5	106.3	11	34.8	28	23.0	3	1.0	3	1.1			50	166.3
	SIC 8211: Schools							90	8.3			26	2.1			116	10.3
	SIC 8220: Colleges/Univ.	1	4.2	7	188.8	6	70.3	26	27.0	3	2.8	9	2.4			52	295.4
	SIC 8400: Zoos/Museums							1	1.4			1	1.0			2	2.3
	SIC 8900: Services NEC					1	5.6	27	2.0	2	0.4	3	0.2	2	0.9	35	9.1
	SIC 9100: Government Fac.			2	30.5	2	11.1	14	9.3	2	0.7	3	0.8			23	52.4
	SIC 9200: Courts/Prisons			2	57.6	2	9.7	7	9.3	4	2.8	2	0.1			17	79.5
	SIC 9700: Military			4	119.2	1	7.5	2	3.3	2	0.7	1	0.1			10	130.8
	Total Commercial	3	56.8	23	610.3	43	492.6	479	273.2	34	19.5	94	16.6	2	0.9	678	1,469.8
	Grand Total	**43**	**988.1**	**47**	**3,316.5**	**139**	**3,665.4**	**737**	**472.7**	**45**	**26.5**	**184**	**31.3**	**7**	**17.4**	**1,202**	**8,517.9**

Source: ICF International, Inc.

APPENDIX C: CHP Technical Potential Detailed Tables

Table C-1: LADWP CHP Technical Potential by Industrial Application

SIC	Application	50-500 kW MW	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total MW
20	Food	3.7	2.9	2.4	24.3	0.0	33.3
22	Textiles	1.2	0.0	0.0	0.0	0.0	1.2
24	Lumber and Wood	0.4	0.0	0.0	0.0	0.0	0.4
25	Furniture	0.0	0.0	0.0	0.0	0.0	0.0
26	Paper	1.1	0.0	4.7	0.0	0.0	5.8
27	Printing	0.0	0.0	0.0	0.0	0.0	0.0
28	Chemicals	4.2	4.1	16.6	26.6	0.0	51.5
29	Petroleum Refining	0.0	0.0	1.2	0.0	0.0	1.2
30	Rubber/Misc Plastics	1.4	0.0	0.0	0.0	0.0	1.4
32	Stone/Clay/Glass	0.3	0.6	8.0	0.0	0.0	8.8
33	Primary Metals	0.1	0.0	0.0	0.0	0.0	0.1
34	Fabricated Metals	1.3	0.7	0.0	0.0	0.0	2.1
35	Machinery/Computer Equip	0.6	0.0	0.0	0.0	0.0	0.6
37	Transportation Equip.	2.3	3.4	4.3	0.0	0.0	10.0
38	Instruments	1.1	0.0	0.0	0.0	0.0	1.1
39	Misc. Manufacturing	0.0	0.0	0.0	0.0	0.0	0.0
	Total	**17.7**	**11.7**	**37.2**	**50.9**	**0.0**	**117.4**

Source: ICF International, Inc.

Table C-2: LADWP CHP Technical Potential by Commercial/Institutional Application

SIC	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	0.4	0.5	0.0	0.0	0.0	0.9
52	Retail	14.8	5.2	1.0	0.0	0.0	21.0
4222	Refrigerated Warehouses	2.7	1.4	0.0	0.0	0.0	4.1
4581	Airports	0.0	0.0	0.0	0.0	26.6	26.6
4952	Water Treatment	0.7	0.0	1.3	0.0	0.0	1.9
5411	Food Stores	15.5	1.6	0.0	0.0	0.0	17.0
5812	Restaurants	11.1	1.0	2.1	0.0	0.0	14.1
6512	Commercial Buildings	78.8	98.6	136.9	0.0	0.0	314.3
6513	Multifamily Buildings	0.1	34.5	22.5	0.0	0.0	57.1
7011	Hotels	9.6	9.0	21.5	0.0	0.0	40.1
7211	Laundries	2.6	1.1	0.0	0.0	0.0	3.7
7374	Data Centers	1.4	0.7	1.3	0.0	0.0	3.4
7542	Car Washes	1.3	0.0	0.0	0.0	0.0	1.3
7832	Movie Theaters	0.5	0.0	0.0	0.0	0.0	0.5
7991	Health Clubs	3.9	0.6	0.0	0.0	0.0	4.5
7997	Golf/Country Clubs	1.4	0.0	0.0	0.0	0.0	1.4
8051	Nursing Homes	9.4	0.6	1.4	0.0	0.0	11.5
8062	Hospitals	5.3	5.0	29.5	7.4	0.0	47.2
8211	Schools	27.9	4.5	5.4	0.0	0.0	37.8
8221	College/Univ.	4.5	2.8	13.1	93.7	127.5	241.5
8412	Museums	2.0	0.8	0.0	0.0	0.0	2.8
9100	Government Buildings	16.0	9.6	24.5	45.1	24.8	120.0
9223	Prisons	1.3	0.0	1.8	0.0	0.0	3.2
	Total	**211.1**	**177.4**	**262.3**	**146.2**	**179.0**	**976.0**

Source: ICF International, Inc.

Table C-3: PG&E CHP Technical Potential by Industrial Application

SIC	Application	50-500 kW MW	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total MW
20	Food	106.4	46.0	129.9	82.4	56.3	421.0
22	Textiles	6.2	0.0	1.6	0.0	0.0	7.7
24	Lumber and Wood	26.0	9.1	36.9	22.6	25.0	119.5
25	Furniture	0.1	0.0	0.0	0.0	0.0	0.1
26	Paper	16.3	11.1	48.8	33.0	20.0	129.2
27	Printing	0.3	0.0	2.5	0.0	0.0	2.8
28	Chemicals	45.0	30.4	113.4	131.8	75.4	396.1
29	Petroleum Refining	4.0	10.1	26.7	10.8	0.0	51.7
30	Rubber/Misc Plastics	9.0	3.0	4.9	6.4	0.0	23.3
32	Stone/Clay/Glass	2.5	4.6	6.4	0.0	0.0	13.6
33	Primary Metals	5.9	0.5	3.6	0.0	0.0	10.0
34	Fabricated Metals	2.4	0.6	0.0	0.0	0.0	3.0
35	Machinery/Computer Equip	4.3	1.6	8.8	0.0	0.0	14.6
37	Transportation Equip.	3.4	0.0	3.3	19.4	0.0	26.1
38	Instruments	5.3	0.7	1.4	0.0	0.0	7.5
39	Misc. Manufacturing	0.0	0.0	0.0	0.0	0.0	0.0
	Total	**237.3**	**117.7**	**388.2**	**306.3**	**176.6**	**1,226.1**

Source: ICF International, Inc.

Table C-4: PG&E CHP Technical Potential by Commercial/Institutional Application

SIC	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	3.3	0.0	0.0	0.0	0.0	3.3
52	Retail	86.5	10.7	7.3	0.0	0.0	104.5
4222	Refrigerated Warehouses	5.1	1.8	2.2	5.1	0.0	14.1
4581	Airports	1.3	1.6	3.6	12.4	0.0	19.0
4952	Water Treatment	10.4	3.0	3.2	0.0	0.0	16.6
5411	Food Stores	90.2	2.6	3.1	0.0	0.0	95.9
5812	Restaurants	55.6	0.6	0.0	0.0	0.0	56.2
6512	Commercial Buildings	104.1	130.2	180.6	0.0	0.0	414.9
6513	Multifamily Buildings	77.3	36.3	23.8	0.0	0.0	137.3
7011	Hotels	64.4	32.1	35.2	7.5	0.0	139.1
7211	Laundries	8.4	3.4	0.0	0.0	0.0	11.7
7374	Data Centers	6.8	3.8	1.3	0.0	0.0	11.9
7542	Car Washes	5.6	0.0	0.0	0.0	0.0	5.6
7832	Movie Theaters	0.1	0.0	0.0	0.0	0.0	0.1
7991	Health Clubs	22.9	3.6	3.0	0.0	0.0	29.5
7997	Golf/Country Clubs	23.9	0.0	1.2	0.0	0.0	25.2
8051	Nursing Homes	46.2	1.4	3.2	0.0	0.0	50.8
8062	Hospitals	19.5	25.0	110.0	34.7	0.0	189.1
8211	Schools	65.0	7.8	12.9	0.0	0.0	85.7
8221	College/Univ.	23.3	12.0	93.1	225.2	120.4	474.0
8412	Museums	3.1	0.0	0.0	0.0	0.0	3.1
9100	Government Buildings	68.8	39.9	103.2	0.0	0.0	212.0
9223	Prisons	3.6	1.4	23.1	0.0	0.0	28.1
	Total	**795.3**	**317.2**	**610.0**	**284.9**	**120.4**	**2,127.7**

Source: ICF International, Inc.

Table C-5: SCE CHP Technical Potential by Industrial Application

SIC	Application	50-500 kW MW	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total MW
20	Food	88.2	37.8	83.5	26.3	0.0	235.8
22	Textiles	31.4	8.5	26.6	7.7	26.3	100.5
24	Lumber and Wood	17.7	1.9	5.2	0.0	0.0	24.7
25	Furniture	0.1	0.0	0.0	0.0	0.0	0.1
26	Paper	36.3	30.3	75.9	81.9	0.0	224.3
27	Printing	0.0	0.0	0.0	0.0	0.0	0.0
28	Chemicals	74.4	45.1	212.3	166.0	21.3	519.1
29	Petroleum Refining	4.8	14.4	31.9	46.9	100.9	198.9
30	Rubber/Misc Plastics	25.2	12.1	11.4	0.0	0.0	48.8
32	Stone/Clay/Glass	6.2	4.6	1.1	0.0	0.0	11.9
33	Primary Metals	19.1	4.4	9.1	9.2	0.0	41.9
34	Fabricated Metals	7.7	1.4	1.2	0.0	0.0	10.2
35	Machinery/Computer Equip	4.1	1.5	1.1	0.0	0.0	6.7
37	Transportation Equip.	9.9	9.0	1.0	7.0	0.0	26.9
38	Instruments	3.0	0.6	0.0	0.0	36.5	40.0
39	Misc. Manufacturing	0.1	0.0	0.0	0.0	0.0	0.1
	Total	**328.0**	**171.5**	**460.2**	**345.1**	**185.0**	**1,489.8**

Source: ICF International, Inc.

Table C-6: SCE CHP Technical Potential by Commercial/Institutional Application

SIC	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	3.0	0.8	0.0	0.0	0.0	3.8
52	Retail	99.5	12.0	5.9	0.0	0.0	117.5
4222	Refrigerated Warehouses	4.4	1.3	0.0	0.0	0.0	5.7
4581	Airports	0.2	0.0	4.9	0.0	0.0	5.0
4952	Water Treatment	11.9	3.7	2.5	0.0	0.0	18.1
5411	Food Stores	77.7	1.9	3.6	0.0	0.0	83.3
5812	Restaurants	62.3	5.0	2.3	8.9	0.0	78.4
6512	Commercial Buildings	73.4	91.8	127.5	0.0	0.0	292.7
6513	Multifamily Buildings	24.0	23.0	15.0	0.0	0.0	62.0
7011	Hotels	55.5	16.5	52.3	14.9	0.0	139.2
7211	Laundries	7.9	0.0	1.1	0.0	0.0	9.0
7374	Data Centers	7.4	0.0	1.5	0.0	0.0	8.9
7542	Car Washes	7.9	0.8	0.0	0.0	0.0	8.6
7832	Movie Theaters	0.1	0.0	1.4	0.0	0.0	1.5
7991	Health Clubs	18.2	0.7	0.0	0.0	0.0	19.0
7997	Golf/Country Clubs	27.2	0.7	1.1	0.0	0.0	29.0
8051	Nursing Homes	47.5	0.6	9.1	0.0	0.0	57.2
8062	Hospitals	20.1	16.7	85.0	10.7	0.0	132.5
8211	Schools	87.2	7.4	8.3	0.0	0.0	102.9
8221	College/Univ.	14.2	5.2	81.0	219.3	103.9	423.6
8412	Museums	2.1	0.0	0.0	0.0	0.0	2.1
9100	Government Buildings	57.2	22.5	77.3	5.1	0.0	162.1
9223	Prisons	3.2	2.9	1.4	0.0	0.0	7.5
	Total	**712.0**	**213.5**	**481.3**	**258.9**	**103.9**	**1,769.6**

Source: ICF International, Inc.

Table C-7: SDG&E CHP Technical Potential by Industrial Application

SIC	Application	50-500 kW MW	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total MW
20	Food	11.1	8.7	7.3	0.0	0.0	27.1
22	Textiles	1.0	0.0	0.0	0.0	0.0	1.0
24	Lumber and Wood	2.1	0.0	0.0	0.0	0.0	2.1
25	Furniture	0.1	0.0	0.0	0.0	0.0	0.1
26	Paper	3.2	4.0	10.9	0.0	0.0	18.1
27	Printing	0.0	0.0	0.0	0.0	0.0	0.0
28	Chemicals	14.6	12.4	23.4	22.0	0.0	72.4
29	Petroleum Refining	1.2	4.5	0.0	0.0	23.7	29.4
30	Rubber/Misc Plastics	2.3	1.2	0.0	0.0	0.0	3.5
32	Stone/Clay/Glass	1.5	0.0	1.1	0.0	0.0	2.6
33	Primary Metals	1.2	0.0	0.0	0.0	0.0	1.2
34	Fabricated Metals	0.9	0.0	0.0	0.0	0.0	0.9
35	Machinery/Computer Equip	1.1	0.8	0.0	0.0	0.0	1.9
37	Transportation Equip.	2.0	0.6	0.0	0.0	0.0	2.5
38	Instruments	2.2	0.0	1.2	0.0	0.0	3.4
39	Misc. Manufacturing	0.0	0.0	0.0	0.0	0.0	0.0
	Total	**44.4**	**32.3**	**43.9**	**22.0**	**23.7**	**166.3**

Source: ICF International, Inc.

Table C-8: SDG&E CHP Technical Potential by Commercial/Institutional Application

SIC	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	0.4	0.0	0.0	0.0	0.0	0.4
52	Retail	22.3	3.5	1.1	0.0	0.0	26.9
4222	Refrigerated Warehouses	1.1	0.0	0.0	0.0	0.0	1.1
4581	Airports	0.0	0.0	0.0	10.8	0.0	10.8
4952	Water Treatment	2.3	0.0	0.0	0.0	0.0	2.3
5411	Food Stores	17.2	0.0	0.0	0.0	0.0	17.2
5812	Restaurants	18.2	2.0	2.6	0.0	0.0	22.7
6512	Commercial Buildings	24.0	30.0	41.9	0.0	0.0	95.9
6513	Multifamily Buildings	0.3	12.0	7.5	0.0	0.0	19.8
7011	Hotels	20.3	11.1	43.4	15.8	0.0	90.6
7211	Laundries	2.0	0.0	0.0	0.0	0.0	2.0
7374	Data Centers	1.1	0.7	1.5	0.0	0.0	3.3
7542	Car Washes	1.0	0.0	0.0	0.0	0.0	1.0
7832	Movie Theaters	0.3	0.0	0.0	0.0	0.0	0.3
7991	Health Clubs	5.6	0.0	0.0	0.0	0.0	5.6
7997	Golf/Country Clubs	7.1	0.0	0.0	0.0	0.0	7.1
8051	Nursing Homes	11.6	0.7	0.0	0.0	0.0	12.2
8062	Hospitals	3.3	3.8	19.3	5.4	0.0	31.9
8211	Schools	18.3	3.3	1.4	0.0	0.0	23.0
8221	College/Univ.	3.9	1.5	22.8	49.5	22.7	100.3
8412	Museums	1.6	0.5	0.0	0.0	0.0	2.1
9100	Government Buildings	12.3	3.5	25.0	5.7	0.0	46.5
9223	Prisons	1.7	0.0	1.4	0.0	0.0	3.1
	Total	**175.8**	**72.5**	**167.7**	**87.3**	**22.7**	**525.9**

Source: ICF International, Inc.

Table C-9: SMUD CHP Technical Potential by Industrial Application

SIC	Application	50-500 kW MW	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total MW
20	Food	3.1	4.1	3.1	5.0	0.0	15.3
22	Textiles	0.5	0.0	0.0	0.0	0.0	0.5
24	Lumber and Wood	1.9	1.8	0.0	0.0	0.0	3.7
25	Furniture	0.0	0.0	0.0	0.0	0.0	0.0
26	Paper	1.1	1.2	12.5	5.2	0.0	20.0
27	Printing	0.0	0.0	0.0	0.0	0.0	0.0
28	Chemicals	3.4	1.5	5.0	0.0	0.0	9.9
29	Petroleum Refining	0.0	0.0	1.1	0.0	0.0	1.1
30	Rubber/Misc Plastics	0.8	0.0	0.0	0.0	0.0	0.8
32	Stone/Clay/Glass	0.2	1.5	0.0	0.0	0.0	1.7
33	Primary Metals	0.1	0.0	0.0	0.0	0.0	0.1
34	Fabricated Metals	0.0	0.0	0.0	0.0	0.0	0.0
35	Machinery/Computer Equip	0.0	0.0	0.0	0.0	0.0	0.0
37	Transportation Equip.	0.1	0.0	6.8	0.0	0.0	6.9
38	Instruments	0.2	0.0	0.0	0.0	0.0	0.2
39	Misc. Manufacturing	0.0	0.0	0.0	0.0	0.0	0.0
	Total	**11.3**	**10.1**	**28.7**	**10.2**	**0.0**	**60.3**

Source: ICF International, Inc.

Table C-10: SMUD CHP Technical Potential by Commercial/Institutional Application

SIC	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	0.0	0.6	0.0	0.0	0.0	0.6
52	Retail	7.2	0.6	0.0	0.0	0.0	7.7
4222	Refrigerated Warehouses	1.0	0.0	0.0	0.0	0.0	1.0
4581	Airports	0.0	0.0	0.0	6.0	0.0	6.0
4952	Water Treatment	0.8	0.0	0.0	0.0	0.0	0.8
5411	Food Stores	6.0	0.8	1.1	0.0	0.0	7.9
5812	Restaurants	4.4	0.0	0.0	0.0	0.0	4.4
6512	Commercial Buildings	11.2	14.0	19.4	0.0	0.0	44.5
6513	Multifamily Buildings	2.3	4.8	3.1	0.0	0.0	10.3
7011	Hotels	5.0	2.3	1.1	0.0	0.0	8.4
7211	Laundries	2.0	0.0	1.0	0.0	0.0	3.0
7374	Data Centers	1.5	0.9	1.5	0.0	0.0	3.9
7542	Car Washes	0.4	0.0	0.0	0.0	0.0	0.4
7832	Movie Theaters	0.0	0.0	0.0	0.0	0.0	0.0
7991	Health Clubs	0.9	0.6	0.0	0.0	0.0	1.5
7997	Golf/Country Clubs	1.0	0.0	0.0	0.0	0.0	1.0
8051	Nursing Homes	3.2	0.0	0.0	0.0	0.0	3.2
8062	Hospitals	0.5	0.6	5.9	0.0	0.0	7.0
8211	Schools	4.0	0.5	2.3	0.0	0.0	6.9
8221	College/Univ.	2.1	0.6	3.4	7.3	21.4	34.8
8412	Museums	0.1	0.0	0.0	0.0	0.0	0.1
9100	Government Buildings	15.1	6.7	26.4	60.4	0.0	108.7
9223	Prisons	1.0	0.0	4.4	0.0	0.0	5.4
	Total	**69.7**	**33.0**	**69.7**	**73.7**	**21.4**	**267.4**

Source: ICF International, Inc.

Table C-11: Other North Utilities CHP Technical Potential by Industrial Application

SIC	Application	50-500 kW MW	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total MW
20	Food	5.6	5.2	15.7	37.9	0.0	64.4
22	Textiles	0.2	0.0	0.0	0.0	0.0	0.2
24	Lumber and Wood	4.8	2.9	3.0	0.0	0.0	10.7
25	Furniture	0.0	0.0	0.0	0.0	0.0	0.0
26	Paper	0.2	1.4	1.2	12.2	0.0	15.0
27	Printing	0.0	0.0	0.0	0.0	0.0	0.0
28	Chemicals	0.7	0.8	2.7	0.0	0.0	4.2
29	Petroleum Refining	0.1	0.0	0.0	0.0	0.0	0.1
30	Rubber/Misc Plastics	1.8	0.7	0.0	0.0	0.0	2.5
32	Stone/Clay/Glass	0.4	0.0	5.3	0.0	0.0	5.7
33	Primary Metals	0.3	0.0	0.0	0.0	0.0	0.3
34	Fabricated Metals	0.9	0.0	0.0	0.0	0.0	0.9
35	Machinery/Computer Equip	0.1	0.0	0.0	0.0	0.0	0.1
37	Transportation Equip.	0.2	0.0	0.0	0.0	0.0	0.2
38	Instruments	0.4	0.0	0.0	0.0	0.0	0.4
39	Misc. Manufacturing	0.0	0.0	0.0	0.0	0.0	0.0
	Total	**15.6**	**11.0**	**28.0**	**50.1**	**0.0**	**104.6**

Source: ICF International, Inc.

Table C-12: Other North Utilities CHP Technical Potential by Commercial/Institutional Application

SIC	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	0.1	0.0	0.0	0.0	0.0	0.1
52	Retail	5.9	1.4	0.0	0.0	0.0	7.3
4222	Refrigerated Warehouses	0.4	0.0	0.0	0.0	0.0	0.4
4581	Airports	0.0	0.0	0.0	0.0	0.0	0.0
4952	Water Treatment	0.3	0.0	0.0	0.0	0.0	0.3
5411	Food Stores	5.0	0.6	0.0	0.0	0.0	5.7
5812	Restaurants	2.2	0.0	0.0	0.0	0.0	2.2
6512	Commercial Buildings	1.1	1.4	1.9	0.0	0.0	4.3
6513	Multifamily Buildings	1.1	0.0	0.0	0.0	0.0	1.1
7011	Hotels	3.3	1.2	0.0	0.0	0.0	4.5
7211	Laundries	0.4	0.0	0.0	0.0	0.0	0.4
7374	Data Centers	0.0	0.0	0.0	0.0	0.0	0.0
7542	Car Washes	0.3	0.0	0.0	0.0	0.0	0.3
7832	Movie Theaters	0.1	0.0	0.0	0.0	0.0	0.1
7991	Health Clubs	0.9	0.0	0.0	0.0	0.0	0.9
7997	Golf/Country Clubs	0.6	0.0	0.0	0.0	0.0	0.6
8051	Nursing Homes	3.8	0.6	0.0	0.0	0.0	4.4
8062	Hospitals	2.4	2.3	2.6	0.0	0.0	7.3
8211	Schools	5.6	0.0	0.0	0.0	0.0	5.6
8221	College/Univ.	1.1	0.0	7.3	7.1	0.0	15.5
8412	Museums	0.2	0.0	0.0	0.0	0.0	0.2
9100	Government Buildings	6.2	4.1	2.1	15.0	0.0	27.4
9223	Prisons	0.2	0.0	2.8	0.0	0.0	2.9
	Total	**41.0**	**11.6**	**16.6**	**22.1**	**0.0**	**91.3**

Source: ICF International, Inc.

Table C-13: Other South Utilities CHP Technical Potential by Industrial Application

SIC	Application	50-500 kW MW	500-1 MW (MW)	1-5 MW (MW)	5-20 MW (MW)	>20 MW (MW)	Total MW
20	Food	8.1	4.0	15.8	19.8	0.0	47.8
22	Textiles	5.0	1.9	1.4	0.0	0.0	8.2
24	Lumber and Wood	2.9	1.5	0.0	0.0	0.0	4.4
25	Furniture	0.1	0.0	0.0	0.0	0.0	0.1
26	Paper	2.9	5.5	13.4	0.0	0.0	21.8
27	Printing	0.1	0.0	0.0	0.0	0.0	0.1
28	Chemicals	6.3	4.5	22.5	13.5	0.0	46.7
29	Petroleum Refining	0.6	0.8	1.0	0.0	0.0	2.5
30	Rubber/Misc Plastics	3.8	0.6	1.0	0.0	0.0	5.4
32	Stone/Clay/Glass	0.9	0.7	1.1	0.0	0.0	2.7
33	Primary Metals	1.3	0.0	0.0	0.0	0.0	1.3
34	Fabricated Metals	0.8	0.0	0.0	0.0	0.0	0.8
35	Machinery/Computer Equip	0.2	1.4	0.0	0.0	0.0	1.6
37	Transportation Equip.	0.5	0.0	0.0	0.0	0.0	0.5
38	Instruments	0.4	0.0	0.0	0.0	0.0	0.4
39	Misc. Manufacturing	0.0	0.0	0.0	0.0	0.0	0.0
	Total	**33.7**	**20.9**	**56.3**	**33.3**	**0.0**	**144.1**

Source: ICF International, Inc.

Table C-14: Other South Utilities CHP Technical Potential by Commercial/Institutional Application

SIC	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	0.4	0.0	0.0	0.0	0.0	0.4
52	Retail	9.2	2.4	0.0	0.0	0.0	11.6
4222	Refrigerated Warehouses	1.6	1.1	1.6	0.0	0.0	4.4
4581	Airports	0.0	0.0	0.0	0.0	0.0	0.0
4952	Water Treatment	1.4	0.0	0.0	0.0	0.0	1.4
5411	Food Stores	8.5	0.0	0.0	0.0	0.0	8.5
5812	Restaurants	8.8	0.6	0.0	0.0	0.0	9.4
6512	Commercial Buildings	1.3	1.7	2.5	0.0	0.0	5.4
6513	Multifamily Buildings	0.1	0.2	0.0	0.0	0.0	0.2
7011	Hotels	8.0	4.1	4.9	0.0	0.0	17.0
7211	Laundries	1.5	0.0	0.0	0.0	0.0	1.5
7374	Data Centers	0.7	0.0	0.0	0.0	0.0	0.7
7542	Car Washes	1.3	0.0	0.0	0.0	0.0	1.3
7832	Movie Theaters	0.0	0.0	0.0	0.0	0.0	0.0
7991	Health Clubs	2.4	0.0	0.0	0.0	0.0	2.4
7997	Golf/Country Clubs	1.3	0.0	0.0	0.0	0.0	1.3
8051	Nursing Homes	6.5	0.0	0.0	0.0	0.0	6.5
8062	Hospitals	2.5	2.8	14.4	0.0	0.0	19.7
8211	Schools	7.5	0.0	1.4	9.3	0.0	18.2
8221	College/Univ.	1.4	1.6	8.5	47.1	0.0	58.7
8412	Museums	0.4	0.0	0.0	0.0	0.0	0.4
9100	Government Buildings	6.8	5.5	9.5	0.0	0.0	21.7
9223	Prisons	0.9	0.6	0.0	0.0	0.0	1.4
	Total	**72.5**	**20.4**	**42.8**	**56.4**	**0.0**	**192.1**

Source: ICF International, Inc.

APPENDIX D: Detailed Scenario Results

Table D-1: Base Case LADWP Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	3	16	37	44	45
Commercial/Institutional	12	62	149	180	189
Residential	1	3	8	10	10
Cumulative Market Penetration, MW	16	81	194	233	244
Avoided Electric Cooling, MW	3	13	30	36	37
Scenario Grand Total	19	94	224	269	281
Annual Electric Energy (Million kWh)					
Industrial	24	120	278	325	333
Commercial/Institutional	82	409	958	1137	1,190
Residential	4	18	53	69	73
Total	**109**	**547**	**1,289**	**1,531**	**1596**
Avoided Cooling	9	43	97	114	118
Scenario Grand Total	118	590	1,386	1,644	1,714
CHP Fuel, (billion Btu/year)	1059	5,293	12,315	14,534	15,127
Avoided Boiler Fuel (Billion Btu/year)	281	1,404	3,192	3,755	3,896
Incremental Onsite Fuel (billion Btu/year)	778	3,889	9,122	10,779	11,231
Cumulative Investment (million 2011 $)	$26	$128	$322	$395	$421
Cumulative Capital Incentives(Million 2011 $)	$2	$9	$9	$9	$9
Annual Electric Energy (Million 2011 $)					
Total	**$11.71**	**$58.55**	**$152.86**	**$195.73**	**$211.67**
Avoided Cooling	$1.37	$6.86	$16.57	$20.83	$22.60
Scenario Grand Total	$13.08	$65.41	$169.43	$216.56	$234.27
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$6.88	$34.39	$97.53	$135.85	$159.82
Avoided Boiler Fuel	$2.01	$10.04	$27.39	$37.59	$43.71
Total	**$4.87**	**$24.34**	**$70.14**	**$98.26**	**$116.11**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	0.4	1.9	6.7	10.4	11.4
500kW-1,000kW	1.1	5.4	16.1	22.0	23.5
1-5 MW	3.3	16.3	48.7	61.1	64.3
5-20 MW	4.2	21.2	52.7	61.5	63.9
>20 MW	7.2	35.8	70.0	78.1	80.7
Total Market	**16.1**	**80.6**	**194.2**	**233.1**	**243.9**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	9	46	46	-38	-40
Cumulative Avoided CO_2 Emissions, thousand MT	9	137	368	346	150
Average unit Emissions savings, lb/MWh	170.8	170.8	73.8	-51.1	-51.2
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	14	71	169	204	213
Cumulative Avoided CO_2 Emissions, thousand MT	14	214	865	1,815	2,860
Average unit Emissions savings, lb/MWh	266.9	266.9	269.5	273.0	273.6

Source: ICF International, Inc.

Table D-2: Base Case PG&E Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	30	151	316	375	382
Commercial/Institutional	19	96	257	325	345
Residential	1	4	13	18	19
Cumulative Market Penetration, MW	50	251	586	718	745
Avoided Electric Cooling, MW	4	20	50	62	66
Scenario Grand Total	54	271	636	779	811
Annual Electric Energy (Million kWh)					
Industrial	229	1147	2355	2787	2,836
Commercial/Institutional	124	620	1624	2022	2,135
Residential	6	30	90	123	132
Total	**359**	**1,797**	**4,070**	**4,931**	**5103**
Avoided Cooling	13	64	154	188	198
Scenario Grand Total	372	1,861	4,224	5,120	5,302
CHP Fuel, (billion Btu/year)	3564	17,818	40,025	48,178	49,841
Avoided Boiler Fuel (Billion Btu/year)	1290	6,451	13,577	16,314	16,825
Incremental Onsite Fuel (billion Btu/year)	2,273	11,367	26,448	31,864	33,016
Cumulative Investment (million 2011 $)	$85	$427	$1,069	$1,345	$1,428
Cumulative Capital Incentives(Million 2011 $)	$8	$38	$38	$38	$38
Annual Electric Energy (Million 2011 $)					
Total	**$31.63**	**$158.16**	**$423.84**	**$562.11**	**$608.25**
Avoided Cooling	$2.29	$11.43	$29.34	$38.12	$41.45
Scenario Grand Total	$33.92	$169.59	$453.17	$600.23	$649.70
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$21.43	$107.14	$295.81	$422.25	$495.83
Avoided Boiler Fuel	$9.28	$46.39	$117.71	$164.11	$189.09
Total	**$12.15**	**$60.75**	**$178.10**	**$258.14**	**$306.75**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	4.4	21.8	69.0	102.6	113.0
500kW-1,000kW	2.9	14.6	43.3	58.1	61.4
1-5 MW	12.6	62.8	184.9	227.7	236.3
5-20 MW	13.2	65.8	163.0	186.6	190.1
>20 MW	17.1	85.7	126.0	142.6	144.6
Total Market	**50.1**	**250.7**	**586.2**	**717.5**	**745.5**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	39	195	232	20	17
Cumulative Avoided CO_2 Emissions, thousand MT	39	585	1,672	2,196	2,288
Average unit Emissions savings, lb/MWh	231.1	231.1	121.3	8.5	7.3
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	52	262	576	709	734
Cumulative Avoided CO_2 Emissions, thousand MT	52	787	3,040	6,319	9,939
Average unit Emissions savings, lb/MWh	310.8	310.8	300.7	305.3	305.2

Source: ICF International, Inc.

Table D-3: Base Case SCE Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	17	87	217	254	257
Commercial/Institutional	8	42	108	132	138
Residential	0	1	1	2	2
Cumulative Market Penetration, MW	26	130	326	388	397
Avoided Electric Cooling, MW	2	9	20	24	25
Scenario Grand Total	28	139	347	412	422
Annual Electric Energy (Million kWh)					
Industrial	132	661	1622	1893	1,915
Commercial/Institutional	56	282	707	850	886
Residential	1	4	9	11	12
Total	**189**	**947**	**2,337**	**2,755**	**2812**
Avoided Cooling	6	29	67	78	81
Scenario Grand Total	195	976	2,404	2,833	2,893
CHP Fuel, (billion Btu/year)	1831	9,157	22,233	26,036	26,560
Avoided Boiler Fuel (Billion Btu/year)	672	3,362	7,874	9,207	9,365
Incremental Onsite Fuel (billion Btu/year)	1,159	5,795	14,359	16,829	17,195
Cumulative Investment (million 2011 $)	$38	$192	$497	$600	$627
Cumulative Capital Incentives(Million 2011 $)	$3	$14	$14	$14	$14
Annual Electric Energy (Million 2011 $)					
Total	**$14.17**	**$70.86**	**$199.25**	**$258.89**	**$277.06**
Avoided Cooling	$0.97	$4.83	$11.76	$14.77	$15.86
Scenario Grand Total	$15.14	$75.69	$211.01	$273.66	$292.92
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$11.75	$58.77	$171.60	$236.49	$272.27
Avoided Boiler Fuel	$4.74	$23.69	$65.73	$89.47	$101.81
Total	**$7.02**	**$35.09**	**$105.87**	**$147.01**	**$170.45**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	0.1	0.3	4.2	9.1	10.0
500kW-1,000kW	1.3	6.7	18.9	25.9	27.1
1-5 MW	6.5	32.7	97.8	120.5	124.1
5-20 MW	9.5	47.3	123.1	141.7	144.0
>20 MW	8.6	42.9	82.3	90.5	91.5
Total Market	**26.0**	**130.0**	**326.4**	**387.6**	**396.7**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	22	111	173	64	64
Cumulative Avoided CO_2 Emissions, thousand MT	22	332	1,074	1,612	1,932
Average unit Emissions savings, lb/MWh	250.1	250.1	159.1	49.6	48.7
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	30	148	362	432	441
Cumulative Avoided CO_2 Emissions, thousand MT	30	444	1,827	3,847	6,033
Average unit Emissions savings, lb/MWh	334.6	334.6	331.9	336.2	335.9

Source: ICF International, Inc.

Table D-4: Base Case SDG&E Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	5	25	56	64	65
Commercial/Institutional	5	26	69	88	94
Residential	0	1	2	3	3
Cumulative Market Penetration, MW	10	52	128	155	162
Avoided Electric Cooling, MW	1	5	13	17	18
Scenario Grand Total	11	57	141	172	180
Annual Electric Energy (Million kWh)					
Industrial	39	194	426	488	495
Commercial/Institutional	33	164	436	546	581
Residential	1	6	17	22	23
Total	**73**	**364**	**879**	**1,055**	**1099**
Avoided Cooling	3	17	42	51	54
Scenario Grand Total	76	381	921	1,107	1,153
CHP Fuel, (billion Btu/year)	720	3,601	8,578	10,239	10,644
Avoided Boiler Fuel (Billion Btu/year)	242	1,209	2,713	3,208	3,314
Incremental Onsite Fuel (billion Btu/year)	478	2,392	5,864	7,031	7,330
Cumulative Investment (million 2011 $)	$16	$82	$215	$270	$289
Cumulative Capital Incentives(Million 2011 $)	$1	$7	$7	$7	$7
Annual Electric Energy (Million 2011 $)					
Total	**$6.30**	**$31.48**	**$87.04**	**$116.12**	**$127.28**
Avoided Cooling	$0.63	$3.16	$8.19	$10.64	$11.62
Scenario Grand Total	$6.93	$34.64	$95.23	$126.76	$138.90
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$4.66	$23.31	$66.44	$93.33	$109.38
Avoided Boiler Fuel	$2.15	$10.73	$27.26	$36.51	$41.47
Total	**$2.52**	**$12.58**	**$39.18**	**$56.81**	**$67.91**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	0.7	3.5	11.1	16.7	18.2
500kW-1,000kW	0.7	3.7	11.0	14.8	15.6
1-5 MW	2.6	13.0	38.4	47.9	50.2
5-20 MW	2.5	12.7	31.6	37.3	39.3
>20 MW	3.7	18.6	35.5	38.6	38.9
Total Market	**10.3**	**51.5**	**127.6**	**155.2**	**162.2**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	7	37	50	5	5
Cumulative Avoided CO_2 Emissions, thousand MT	7	110	333	449	474
Average unit Emissions savings, lb/MWh	212.3	212.3	119.4	10.9	8.6
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	10	50	117	143	149
Cumulative Avoided CO_2 Emissions, thousand MT	10	149	600	1,264	1,997
Average unit Emissions savings, lb/MWh	287.4	287.4	281.1	284.8	284.7

Source: ICF International, Inc.

Table D-5: Base Case SMUD Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	1	5	14	17	17
Commercial/Institutional	2	11	27	33	34
Residential	0	0	1	1	1
Cumulative Market Penetration, MW	3	16	42	51	53
Avoided Electric Cooling, MW	0	2	5	6	6
Scenario Grand Total	4	18	47	57	59
Annual Electric Energy (Million kWh)					
Industrial	7	35	99	120	123
Commercial/Institutional	13	65	160	191	200
Residential	0	2	6	8	9
Total	**21**	**103**	**264**	**319**	**332**
Avoided Cooling	1	7	15	17	18
Scenario Grand Total	22	109	279	336	350
CHP Fuel, (billion Btu/year)	203	1,017	2,563	3,066	3,186
Avoided Boiler Fuel (Billion Btu/year)	62	310	765	919	953
Incremental Onsite Fuel (billion Btu/year)	141	707	1,798	2,148	2,233
Cumulative Investment (million 2011 $)	$5	$26	$70	$87	$92
Cumulative Capital Incentives(Million 2011 $)	$0	$2	$2	$2	$2
Annual Electric Energy (Million 2011 $)					
Total	**$1.99**	**$9.96**	**$28.15**	**$36.88**	**$39.99**
Avoided Cooling	$0.16	$0.81	$1.98	$2.49	$2.68
Scenario Grand Total	$2.15	$10.77	$30.13	$39.36	$42.66
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$1.24	$6.18	$19.02	$27.01	$31.85
Avoided Boiler Fuel	$0.46	$2.29	$6.67	$9.29	$10.75
Total	**$0.78**	**$3.89**	**$12.34**	**$17.71**	**$21.09**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	0.1	0.5	1.8	2.7	2.9
500kW-1,000kW	0.2	1.0	2.8	3.8	4.0
1-5 MW	0.9	4.7	13.8	16.9	17.5
5-20 MW	1.3	6.4	16.6	19.8	20.8
>20 MW	0.7	3.4	6.7	7.4	7.6
Total Market	**3.2**	**16.0**	**41.7**	**50.6**	**52.8**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	2	9	12	-4	-4
Cumulative Avoided CO_2 Emissions, thousand MT	2	28	81	94	75
Average unit Emissions savings, lb/MWh	185.9	185.9	92.9	-24.9	-23.9
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	3	14	36	44	46
Cumulative Avoided CO_2 Emissions, thousand MT	3	42	178	383	612
Average unit Emissions savings, lb/MWh	282.5	282.5	284.4	291.1	292.0

Source: ICF International, Inc.

Table D-6: Base Case Other North Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	3	13	32	38	40
Commercial/Institutional	1	4	10	13	14
Residential	0	0	0	0	0
Cumulative Market Penetration, MW	3	16	42	51	54
Avoided Electric Cooling, MW	0	1	2	2	2
Scenario Grand Total	3	17	44	53	56
Annual Electric Energy (Million kWh)					
Industrial	19	95	234	281	293
Commercial/Institutional	4	22	61	77	81
Residential	0	0	0	1	1
Total	**23**	**117**	**295**	**358**	**375**
Avoided Cooling	0	2	5	6	7
Scenario Grand Total	24	119	301	365	381
CHP Fuel, (billion Btu/year)	232	1,158	2,876	3,457	3,606
Avoided Boiler Fuel (Billion Btu/year)	92	461	1,088	1,305	1,361
Incremental Onsite Fuel (billion Btu/year)	139	697	1,788	2,152	2,246
Cumulative Investment (million 2011 $)	$5	$26	$69	$86	$91
Cumulative Capital Incentives(Million 2011 $)	$0	$2	$2	$2	$2
Annual Electric Energy (Million 2011 $)					
Total	**$2.28**	**$11.38**	**$32.29**	**$42.45**	**$46.19**
Avoided Cooling	$0.06	$0.30	$0.81	$1.07	$1.17
Scenario Grand Total	$2.34	$11.68	$33.10	$43.52	$47.36
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$1.38	$6.89	$20.81	$29.67	$35.11
Avoided Boiler Fuel	$0.66	$3.32	$9.27	$12.88	$14.98
Total	**$0.71**	**$3.57**	**$11.55**	**$16.79**	**$20.12**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	0.2	0.9	2.8	4.3	4.7
500kW-1,000kW	0.2	0.9	2.7	3.6	3.9
1-5 MW	0.7	3.7	10.9	13.5	14.0
5-20 MW	1.7	8.6	21.3	24.9	25.8
>20 MW	0.5	2.4	4.3	5.0	5.2
Total Market	**3.3**	**16.4**	**42.0**	**51.2**	**53.6**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	3	14	22	9	9
Cumulative Avoided CO_2 Emissions, thousand MT	3	42	136	206	253
Average unit Emissions savings, lb/MWh	257.5	257.5	162.1	53.8	54.7
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	4	18	46	56	59
Cumulative Avoided CO_2 Emissions, thousand MT	4	55	228	488	778
Average unit Emissions savings, lb/MWh	339.7	339.7	334.6	340.6	341.9

Source: ICF International, Inc.

Table D-7: Base Case Other South Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	2	11	31	37	39
Commercial/Institutional	2	9	25	31	33
Residential	0	0	0	0	0
Cumulative Market Penetration, MW	4	20	55	68	71
Avoided Electric Cooling, MW	0	2	4	5	6
Scenario Grand Total	4	22	60	74	77
Annual Electric Energy (Million kWh)					
Industrial	16	79	220	269	277
Commercial/Institutional	12	62	167	206	217
Residential	0	0	0	0	0
Total	**28**	**141**	**387**	**475**	**494**
Avoided Cooling	1	6	15	18	19
Scenario Grand Total	29	147	402	493	512
CHP Fuel, (billion Btu/year)	286	1,428	3,812	4,629	4,806
Avoided Boiler Fuel (Billion Btu/year)	98	492	1,265	1,541	1,597
Incremental Onsite Fuel (billion Btu/year)	187	935	2,548	3,088	3,208
Cumulative Investment (million 2011 $)	$7	$33	$94	$119	$127
Cumulative Capital Incentives(Million 2011 $)	$1	$4	$4	$4	$4
Annual Electric Energy (Million 2011 $)					
Total	**$3.06**	**$15.29**	**$45.72**	**$60.42**	**$65.18**
Avoided Cooling	$0.18	$0.90	$2.36	$3.05	$3.30
Scenario Grand Total	$3.24	$16.19	$48.08	$63.46	$68.48
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$1.88	$9.40	$30.45	$43.55	$51.02
Avoided Boiler Fuel	$0.74	$3.69	$11.26	$15.94	$18.45
Total	**$1.14**	**$5.71**	**$19.19**	**$27.61**	**$32.57**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	0.3	1.4	5.0	7.6	8.2
500kW-1,000kW	0.3	1.6	4.6	6.1	6.4
1-5 MW	1.3	6.5	19.1	23.4	24.2
5-20 MW	2.1	10.6	26.7	31.2	32.3
>20 MW	0.0	0.0	0.0	0.0	0.0
Total Market	**4.0**	**20.1**	**55.4**	**68.3**	**71.1**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	3	13	18	-4	-4
Cumulative Avoided CO_2 Emissions, thousand MT	3	40	122	146	125
Average unit Emissions savings, lb/MWh	198.3	198.3	101.3	-18.9	-17.8
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	4	20	54	69	71
Cumulative Avoided CO_2 Emissions, thousand MT	4	60	263	578	929
Average unit Emissions savings, lb/MWh	298.2	298.2	298.8	306.7	307.6

Source: ICF International, Inc.

Table D-8: Medium Case LADWP Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	10	50	124	141	142
Commercial/Institutional	13	67	170	205	216
Residential	1	3	9	12	13
Cumulative Market Penetration, MW	24	120	304	358	371
Avoided Electric Cooling, MW	3	14	34	41	42
Scenario Grand Total	27	134	338	399	414
Annual Electric Energy (Million kWh)					
Industrial	79	395	973	1103	1,116
Commercial/Institutional	88	440	1077	1283	1,345
Residential	4	20	66	85	90
Total	**171**	**855**	**2,117**	**2,471**	**2551**
Avoided Cooling	9	46	109	128	133
Scenario Grand Total	180	902	2,226	2,599	2,685
CHP Fuel, (billion Btu/year)	1633	8,164	19,935	23,161	23,893
Avoided Boiler Fuel (Billion Btu/year)	516	2,578	6,216	7,155	7,339
Incremental Onsite Fuel (billion Btu/year)	1,117	5,586	13,719	16,006	16,554
Cumulative Investment (million 2011 $)	$36	$180	$458	$552	$586
Cumulative Capital Incentives(Million 2011 $)	$2	$10	$28	$32	$32
Annual Electric Energy (Million 2011 $)					
Total	**$16.05**	**$80.27**	**$218.32**	**$278.36**	**$302.29**
Avoided Cooling	$1.48	$7.38	$18.56	$23.42	$25.43
Scenario Grand Total	$17.53	$87.64	$236.88	$301.78	$327.72
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$10.24	$51.18	$146.97	$200.66	$233.61
Avoided Boiler Fuel	$3.49	$17.47	$48.25	$64.39	$73.83
Total	**$6.74**	**$33.71**	**$98.72**	**$136.27**	**$159.78**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	0.5	2.3	10.3	15.5	16.9
500kW-1,000kW	1.2	6.2	21.4	28.9	30.8
1-5 MW	3.6	18.0	58.2	72.7	76.5
5-20 MW	4.5	22.4	56.6	66.0	68.5
>20 MW	14.2	71.1	157.1	175.1	178.6
Total Market	**24.0**	**120.1**	**303.5**	**358.1**	**371.3**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	18	91	160	77	76
Cumulative Avoided CO_2 Emissions, thousand MT	18	274	936	1,485	1,866
Average unit Emissions savings, lb/MWh	223.5	223.5	158.1	65.1	62.1
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	24	119	299	351	362
Cumulative Avoided CO_2 Emissions, thousand MT	24	357	1,492	3,143	4,932
Average unit Emissions savings, lb/MWh	291.3	291.3	295.9	297.8	297.6

Source: ICF International, Inc.

Table D-9: Medium Case PG&E Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	95	473	1194	1357	1,373
Commercial/Institutional	21	105	305	386	411
Residential	1	5	17	22	24
Cumulative Market Penetration, MW	117	583	1,515	1,766	1807
Avoided Electric Cooling, MW	4	22	58	73	77
Scenario Grand Total	121	605	1,573	1,839	1,884
Annual Electric Energy (Million kWh)					
Industrial	747	3735	9396	10666	10,781
Commercial/Institutional	136	680	1898	2372	2,509
Residential	7	35	116	157	169
Total	**890**	**4,450**	**11,410**	**13,196**	**13458**
Avoided Cooling	14	70	178	219	231
Scenario Grand Total	904	4,519	11,588	13,415	13,689
CHP Fuel, (billion Btu/year)	8487	42,434	107,169	123,564	126,058
Avoided Boiler Fuel (Billion Btu/year)	3396	16,980	41,783	47,950	48,784
Incremental Onsite Fuel (billion Btu/year)	5,091	25,454	65,387	75,614	77,274
Cumulative Investment (million 2011 $)	$176	$878	$2,274	$2,713	$2,821
Cumulative Capital Incentives(Million 2011 $)	$9	$43	$114	$129	$133
Annual Electric Energy (Million 2011 $)					
Total	**$65.70**	**$328.49**	**$932.58**	**$1,202.30**	**$1,313.28**
Avoided Cooling	$2.50	$12.49	$33.92	$44.27	$48.20
Scenario Grand Total	$68.20	$340.98	$966.50	$1,246.57	$1,361.49
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$48.35	$241.76	$693.35	$938.71	$1,081.59
Avoided Boiler Fuel	$22.35	$111.75	$305.57	$404.12	$457.98
Total	**$26.00**	**$130.01**	**$387.78**	**$534.59**	**$623.61**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	5.3	26.5	93.5	137.4	151.1
500kW-1,000kW	3.3	16.7	56.5	75.0	79.2
1-5 MW	13.8	69.1	218.4	268.1	278.2
5-20 MW	13.9	69.6	174.1	199.0	202.8
>20 MW	80.3	401.3	972.5	1,086.9	1,095.9
Total Market	**116.6**	**583.2**	**1514.8**	**1766.3**	**1807.1**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	122	608	1350	1236	1242
Cumulative Avoided CO_2 Emissions, thousand MT	122	1,823	7,089	13,497	19,696
Average unit Emissions savings, lb/MWh	296.5	296.5	256.9	203.1	200.1
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	136	681	1749	2039	2078
Cumulative Avoided CO_2 Emissions, thousand MT	136	2,044	8,653	18,268	28,580
Average unit Emissions savings, lb/MWh	332.4	332.4	332.7	335.1	334.7

Source: ICF International, Inc.

Table D-10: Medium Case SCE Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	38	189	488	559	564
Commercial/Institutional	9	46	131	160	167
Residential	0	1	2	3	3
Cumulative Market Penetration, MW	47	235	621	721	734
Avoided Electric Cooling, MW	2	9	24	28	29
Scenario Grand Total	49	245	645	749	764
Annual Electric Energy (Million kWh)					
Industrial	295	1476	3779	4315	4,356
Commercial/Institutional	61	305	838	1011	1,054
Residential	1	4	16	20	20
Total	**357**	**1,785**	**4,633**	**5,346**	**5431**
Avoided Cooling	6	31	78	92	95
Scenario Grand Total	363	1,817	4,711	5,437	5,526
CHP Fuel, (billion Btu/year)	3385	16,924	43,332	49,766	50,546
Avoided Boiler Fuel (Billion Btu/year)	1335	6,674	16,656	19,080	19,338
Incremental Onsite Fuel (billion Btu/year)	2,050	10,250	26,676	30,687	31,208
Cumulative Investment (million 2011 $)	$65	$326	$856	$1,009	$1,047
Cumulative Capital Incentives(Million 2011 $)	$3	$15	$45	$51	$52
Annual Electric Energy (Million 2011 $)					
Total	**$25.15**	**$125.76**	**$365.12**	**$466.93**	**$504.84**
Avoided Cooling	$1.04	$5.19	$13.73	$17.25	$18.52
Scenario Grand Total	$26.19	$130.95	$378.85	$484.17	$523.37
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$20.76	$103.81	$307.05	$412.33	$471.03
Avoided Boiler Fuel	$8.91	$44.54	$126.71	$167.76	$189.54
Total	**$11.85**	**$59.27**	**$180.34**	**$244.57**	**$281.49**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	0.1	0.5	10.8	18.4	20.1
500kW-1,000kW	1.5	7.7	29.2	38.7	40.4
1-5 MW	7.2	36.2	123.1	150.6	155.1
5-20 MW	10.0	50.1	132.3	152.1	154.6
>20 MW	28.2	140.9	325.4	361.2	364.1
Total Market	**47.1**	**235.3**	**620.8**	**721.1**	**734.2**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	48	241	507	413	416
Cumulative Avoided CO_2 Emissions, thousand MT	48	723	2,724	4,976	7,048
Average unit Emissions savings, lb/MWh	292.4	292.4	237.0	167.4	165.8
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	56	281	730	851	865
Cumulative Avoided CO_2 Emissions, thousand MT	56	844	3,597	7,610	11,906
Average unit Emissions savings, lb/MWh	341.4	341.4	341.7	345.0	344.9

Source: ICF International, Inc.

Table D-11: Medium Case SDG&E Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	14	69	146	163	164
Commercial/Institutional	6	28	82	104	111
Residential	0	1	3	4	4
Cumulative Market Penetration, MW	20	98	231	270	279
Avoided Electric Cooling, MW	1	6	16	19	21
Scenario Grand Total	21	104	247	290	300
Annual Electric Energy (Million kWh)					
Industrial	109	546	1150	1275	1,287
Commercial/Institutional	36	179	508	638	679
Residential	1	6	21	27	29
Total	**146**	**731**	**1,679**	**1,940**	**1994**
Avoided Cooling	4	19	48	59	63
Scenario Grand Total	150	750	1,728	1,999	2,057
CHP Fuel, (billion Btu/year)	1403	7,014	15,968	18,390	18,903
Avoided Boiler Fuel (Billion Btu/year)	531	2,655	5,725	6,513	6,655
Incremental Onsite Fuel (billion Btu/year)	872	4,360	10,243	11,877	12,248
Cumulative Investment (million 2011 $)	$28	$142	$342	$412	$437
Cumulative Capital Incentives(Million 2011 $)	$2	$8	$23	$26	$27
Annual Electric Energy (Million 2011 $)					
Total	**$11.36**	**$56.81**	**$149.53**	**$193.31**	**$212.09**
Avoided Cooling	$0.69	$3.44	$9.43	$12.30	$13.43
Scenario Grand Total	$12.05	$60.25	$158.96	$205.61	$225.52
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$8.68	$43.41	$114.33	$154.34	$178.47
Avoided Boiler Fuel	$4.57	$22.87	$54.11	$69.19	$77.36
Total	**$4.11**	**$20.54**	**$60.22**	**$85.15**	**$101.12**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	0.8	4.2	15.7	23.1	25.2
500kW-1,000kW	0.9	4.3	14.4	19.1	20.1
1-5 MW	2.9	14.3	45.6	56.7	59.4
5-20 MW	2.7	13.4	33.6	39.7	41.8
>20 MW	12.3	61.6	121.7	131.7	132.5
Total Market	**19.6**	**97.8**	**231.0**	**270.2**	**279.0**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	19	93	163	120	120
Cumulative Avoided CO_2 Emissions, thousand MT	19	279	955	1,642	2,242
Average unit Emissions savings, lb/MWh	273.7	273.7	208.2	132.6	128.3
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	21	107	242	281	289
Cumulative Avoided CO_2 Emissions, thousand MT	21	322	1,262	2,591	4,021
Average unit Emissions savings, lb/MWh	315.4	315.4	308.9	310.3	309.7

Source: ICF International, Inc.

Table D-12: Medium Case SMUD Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	1	5	16	19	20
Commercial/Institutional	2	12	31	38	40
Residential	0	0	1	2	2
Cumulative Market Penetration, MW	3	17	48	58	61
Avoided Electric Cooling, MW	0	2	6	7	7
Scenario Grand Total	4	20	54	65	68
Annual Electric Energy (Million kWh)					
Industrial	8	38	113	137	141
Commercial/Institutional	14	70	182	219	229
Residential	0	2	8	11	11
Total	**22**	**111**	**303**	**366**	**382**
Avoided Cooling	1	7	17	20	20
Scenario Grand Total	24	118	320	386	402
CHP Fuel, (billion Btu/year)	220	1,102	2,942	3,527	3,665
Avoided Boiler Fuel (Billion Btu/year)	67	337	883	1,063	1,102
Incremental Onsite Fuel (billion Btu/year)	153	765	2,059	2,464	2,563
Cumulative Investment (million 2011 $)	$6	$29	$78	$97	$104
Cumulative Capital Incentives(Million 2011 $)	$0	$2	$7	$7	$8
Annual Electric Energy (Million 2011 $)					
Total	**$2.16**	**$10.79**	**$32.48**	**$42.63**	**$46.24**
Avoided Cooling	$0.17	$0.87	$2.24	$2.82	$3.03
Scenario Grand Total	$2.33	$11.66	$34.72	$45.45	$49.27
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$1.34	$6.69	$21.90	$31.17	$36.77
Avoided Boiler Fuel	$0.50	$2.49	$7.77	$10.84	$12.54
Total	**$0.84**	**$4.20**	**$14.13**	**$20.33**	**$24.22**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	0.1	0.7	2.5	3.7	4.1
500kW-1,000kW	0.2	1.1	3.9	5.2	5.5
1-5 MW	1.0	5.2	16.7	20.4	21.0
5-20 MW	1.4	6.8	17.8	21.2	22.2
>20 MW	0.7	3.6	7.1	7.9	8.1
Total Market	**3.5**	**17.3**	**48.0**	**58.4**	**61.0**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	2	10	13	-5	-5
Cumulative Avoided CO_2 Emissions, thousand MT	2	30	90	102	78
Average unit Emissions savings, lb/MWh	185.6	185.6	92.1	-27.3	-26.5
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	3	15	41	51	53
Cumulative Avoided CO_2 Emissions, thousand MT	3	45	200	436	699
Average unit Emissions savings, lb/MWh	282.5	282.5	285.5	292.1	293.0

Source: ICF International, Inc.

Table D-13: Medium Case Other North Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	6	29	74	87	91
Commercial/Institutional	1	4	12	15	16
Residential	0	0	0	0	0
Cumulative Market Penetration, MW	7	33	86	102	107
Avoided Electric Cooling, MW	0	1	2	3	3
Scenario Grand Total	7	34	88	105	110
Annual Electric Energy (Million kWh)					
Industrial	45	223	569	670	701
Commercial/Institutional	5	24	72	91	96
Residential	0	0	1	1	1
Total	**49**	**247**	**641**	**762**	**799**
Avoided Cooling	0	2	6	7	8
Scenario Grand Total	50	249	647	770	807
CHP Fuel, (billion Btu/year)	474	2,372	6,042	7,142	7,471
Avoided Boiler Fuel (Billion Btu/year)	197	983	2,423	2,859	2,991
Incremental Onsite Fuel (billion Btu/year)	278	1,389	3,619	4,283	4,481
Cumulative Investment (million 2011 $)	$10	$48	$123	$149	$159
Cumulative Capital Incentives(Million 2011 $)	$0	$2	$7	$7	$8
Annual Electric Energy (Million 2011 $)					
Total	**$3.98**	**$19.90**	**$57.07**	**$74.68**	**$82.91**
Avoided Cooling	$0.07	$0.33	$0.95	$1.26	$1.38
Scenario Grand Total	$4.05	$20.23	$58.02	$75.94	$84.28
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$2.69	$13.47	$39.49	$54.84	$64.70
Avoided Boiler Fuel	$1.31	$6.54	$18.16	$24.68	$28.70
Total	**$1.39**	**$6.93**	**$21.33**	**$30.16**	**$36.00**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	0.2	1.0	4.0	5.9	6.5
500kW-1,000kW	0.2	1.0	3.5	4.7	5.0
1-5 MW	0.8	4.0	12.7	15.6	16.2
5-20 MW	1.8	9.1	22.8	26.6	27.6
>20 MW	3.5	17.7	42.8	49.7	52.2
Total Market	**6.6**	**32.8**	**85.8**	**102.5**	**107.4**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	7	34	74	67	71
Cumulative Avoided CO_2 Emissions, thousand MT	7	103	394	744	1,093
Average unit Emissions savings, lb/MWh	302.4	302.4	252.8	193.2	194.5
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	8	39	101	122	128
Cumulative Avoided CO_2 Emissions, thousand MT	8	117	498	1,066	1,694
Average unit Emissions savings, lb/MWh	344.8	344.8	344.4	349.0	350.2

Source: ICF International, Inc.

Table D-14: Medium Case Other South Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	2	12	36	43	45
Commercial/Institutional	2	10	29	36	38
Residential	0	0	0	0	0
Cumulative Market Penetration, MW	4	22	65	80	83
Avoided Electric Cooling, MW	0	2	5	6	7
Scenario Grand Total	5	24	70	86	90
Annual Electric Energy (Million kWh)					
Industrial	17	87	255	311	321
Commercial/Institutional	13	67	193	239	252
Residential	0	0	0	0	0
Total	**31**	**154**	**448**	**551**	**573**
Avoided Cooling	1	7	17	20	21
Scenario Grand Total	32	160	465	571	594
CHP Fuel, (billion Btu/year)	312	1,559	4,421	5,381	5,589
Avoided Boiler Fuel (Billion Btu/year)	108	541	1,478	1,805	1,872
Incremental Onsite Fuel (billion Btu/year)	204	1,019	2,942	3,575	3,716
Cumulative Investment (million 2011 $)	$7	$36	$105	$133	$145
Cumulative Capital Incentives(Million 2011 $)	$1	$4	$11	$13	$13
Annual Electric Energy (Million 2011 $)					
Total	**$3.34**	**$16.69**	**$53.18**	**$70.44**	**$76.03**
Avoided Cooling	$0.19	$0.97	$2.69	$3.49	$3.79
Scenario Grand Total	$3.53	$17.66	$55.87	$73.93	$79.82
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$2.06	$10.28	$35.42	$50.77	$59.51
Avoided Boiler Fuel	$0.81	$4.06	$13.26	$18.81	$21.78
Total	**$1.24**	**$6.21**	**$22.16**	**$31.96**	**$37.73**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	0.3	1.7	7.2	10.7	11.6
500kW-1,000kW	0.4	1.8	6.0	7.9	8.3
1-5 MW	1.4	7.1	22.8	27.8	28.6
5-20 MW	2.3	11.3	28.6	33.4	34.6
>20 MW	0.0	0.0	0.0	0.0	0.0
Total Market	**4.4**	**21.9**	**64.6**	**79.7**	**83.0**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	3	14	22	-5	-5
Cumulative Avoided CO_2 Emissions, thousand MT	3	43	137	165	140
Average unit Emissions savings, lb/MWh	198.4	198.4	102.1	-19.2	-18.3
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	4	22	63	80	83
Cumulative Avoided CO_2 Emissions, thousand MT	4	65	299	666	1,076
Average unit Emissions savings, lb/MWh	298.4	298.4	300.8	308.5	309.3

Source: ICF International, Inc.

Table D-15: High Case LADWP Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	19	95	256	293	296
Commercial/Institutional	17	87	240	300	319
Residential	1	4	14	18	20
Cumulative Market Penetration, MW	37	186	509	611	635
Avoided Electric Cooling, MW	4	18	48	59	63
Scenario Grand Total	41	205	557	670	698
Annual Electric Energy (Million kWh)					
Industrial	151	757	2027	2314	2,341
Commercial/Institutional	111	557	1476	1818	1,925
Residential	5	27	97	129	138
Total	**268**	**1,341**	**3,599**	**4,261**	**4404**
Avoided Cooling	12	59	149	181	191
Scenario Grand Total	280	1,400	3,748	4,441	4,595
CHP Fuel, (billion Btu/year)	2392	11,962	31,879	37,763	39,078
Avoided Boiler Fuel (Billion Btu/year)	624	3,118	8,247	9,748	10,064
Incremental Onsite Fuel (billion Btu/year)	1,769	8,843	23,633	28,014	29,014
Cumulative Investment (million 2011 $)	$50	$252	$669	$812	$816
Cumulative Capital Incentives(Million 2011 $)	$3	$17	$60	$78	$83
Annual Electric Energy (Million 2011 $)					
Total	**$23.61**	**$118.04**	**$345.82**	**$450.69**	**$493.60**
Avoided Cooling	$1.88	$9.38	$25.47	$33.20	$36.42
Scenario Grand Total	$25.48	$127.41	$371.28	$483.89	$530.02
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$13.88	$69.38	$196.31	$265.53	$305.63
Avoided Boiler Fuel	$4.02	$20.11	$56.43	$75.52	$85.99
Total	**$9.85**	**$49.27**	**$139.87**	**$190.01**	**$219.63**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	1.1	5.6	23.8	36.9	40.8
500kW-1,000kW	1.9	9.3	33.8	47.2	51.0
1-5 MW	4.9	24.3	84.4	108.7	115.6
5-20 MW	6.0	29.8	80.0	94.8	98.7
>20 MW	23.4	117.2	287.3	323.5	329.0
Total Market	**37.2**	**186.2**	**509.4**	**611.1**	**635.1**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	27	135	268	159	156
Cumulative Avoided CO_2 Emissions, thousand MT	27	405	1,478	2,490	3,276
Average unit Emissions savings, lb/MWh	212.3	212.3	157.5	78.9	75.0
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	34	170	458	545	564
Cumulative Avoided CO_2 Emissions, thousand MT	34	510	2,223	4,775	7,559
Average unit Emissions savings, lb/MWh	267.6	267.6	269.3	270.8	270.8

Source: ICF International, Inc.

Table D-16: High Case PG&E Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	98	491	1429	1665	1,688
Commercial/Institutional	35	173	524	683	733
Residential	2	9	30	41	45
Cumulative Market Penetration, MW	135	673	1,983	2,390	2466
Avoided Electric Cooling, MW	7	36	100	129	138
Scenario Grand Total	142	709	2,083	2,519	2,605
Annual Electric Energy (Million kWh)					
Industrial	768	3842	11147	12958	13,129
Commercial/Institutional	221	1103	3230	4145	4,427
Residential	12	60	208	290	313
Total	**1001**	**5,005**	**14,585**	**17,393**	**17870**
Avoided Cooling	23	113	303	383	407
Scenario Grand Total	1024	5,118	14,887	17,776	18,277
CHP Fuel, (billion Btu/year)	9047	45,233	130,062	155,339	159,882
Avoided Boiler Fuel (Billion Btu/year)	2803	14,013	39,223	46,929	48,249
Incremental Onsite Fuel (billion Btu/year)	6,244	31,220	90,838	108,410	111,634
Cumulative Investment (million 2011 $)	$195	$974	$2,732	$3,334	$3,312
Cumulative Capital Incentives(Million 2011 $)	$16	$79	$262	$340	$361
Annual Electric Energy (Million 2011 $)					
Total	**$88.69**	**$443.46**	**$1,395.87**	**$1,842.30**	**$2,010.34**
Avoided Cooling	$4.42	$22.11	$62.73	$83.81	$91.98
Scenario Grand Total	$93.11	$465.57	$1,458.61	$1,926.11	$2,102.33
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$49.27	$246.34	$752.25	$1,032.53	$1,188.10
Avoided Boiler Fuel	$18.43	$92.15	$272.43	$368.49	$417.39
Total	**$30.84**	**$154.20**	**$479.82**	**$664.03**	**$770.71**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	9.5	47.3	170.5	257.2	285.7
500kW-1,000kW	5.7	28.7	98.6	134.3	143.0
1-5 MW	21.5	107.4	354.3	444.9	464.6
5-20 MW	22.8	113.8	316.0	369.1	376.9
>20 MW	75.2	375.8	1,043.5	1,184.6	1,196.3
Total Market	**134.6**	**673.0**	**1982.9**	**2390.2**	**2466.5**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	111	554	1289	994	992
Cumulative Avoided CO_2 Emissions, thousand MT	111	1,662	6,638	12,198	17,163
Average unit Emissions savings, lb/MWh	238.7	238.7	190.9	123.3	119.7
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	134	669	1937	2330	2393
Cumulative Avoided CO_2 Emissions, thousand MT	134	2,007	9,158	20,023	31,863
Average unit Emissions savings, lb/MWh	288.2	288.2	286.9	289.0	288.7

Source: ICF International, Inc.

Table D-17: High Case SCE Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	73	367	1022	1197	1,213
Commercial/Institutional	23	117	366	479	513
Residential	1	3	11	16	17
Cumulative Market Penetration, MW	97	487	1,399	1,692	1743
Avoided Electric Cooling, MW	5	24	69	89	95
Scenario Grand Total	102	511	1,468	1,781	1,839
Annual Electric Energy (Million kWh)					
Industrial	568	2838	7856	9176	9,294
Commercial/Institutional	151	757	2285	2939	3,138
Residential	4	21	78	109	118
Total	**723**	**3,616**	**10,220**	**12,224**	**12550**
Avoided Cooling	16	78	214	270	286
Scenario Grand Total	739	3,694	10,434	12,494	12,836
CHP Fuel, (billion Btu/year)	6609	33,046	92,730	110,951	114,041
Avoided Boiler Fuel (Billion Btu/year)	2156	10,782	29,606	35,536	36,461
Incremental Onsite Fuel (billion Btu/year)	4,453	22,263	63,124	75,414	77,580
Cumulative Investment (million 2011 $)	$131	$655	$1,816	$2,221	$2,205
Cumulative Capital Incentives(Million 2011 $)	$11	$54	$194	$254	$268
Annual Electric Energy (Million 2011 $)					
Total	**$58.69**	**$293.45**	**$918.03**	**$1,211.67**	**$1,316.43**
Avoided Cooling	$2.96	$14.79	$43.09	$57.68	$63.37
Scenario Grand Total	$61.65	$308.24	$961.11	$1,269.34	$1,379.80
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$38.53	$192.64	$573.87	$783.70	$895.56
Avoided Boiler Fuel	$14.19	$70.96	$206.94	$280.98	$317.49
Total	**$24.34**	**$121.69**	**$366.93**	**$502.72**	**$578.07**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	5.6	28.1	117.4	180.0	197.3
500kW-1,000kW	4.3	21.6	77.0	104.8	110.8
1-5 MW	16.9	84.5	288.2	362.4	377.4
5-20 MW	21.6	108.0	303.6	357.1	364.0
>20 MW	48.9	244.4	613.1	687.5	693.9
Total Market	**97.3**	**486.6**	**1399.3**	**1691.8**	**1743.4**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	82	412	882	617	617
Cumulative Avoided CO_2 Emissions, thousand MT	82	1,237	4,708	8,325	11,410
Average unit Emissions savings, lb/MWh	246.0	246.0	186.4	108.9	106.0
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	101	504	1418	1717	1763
Cumulative Avoided CO_2 Emissions, thousand MT	101	1,513	6,777	14,765	23,488
Average unit Emissions savings, lb/MWh	301.1	301.1	299.7	303.0	302.8

Source: ICF International, Inc.

Table D-18: High Case SDG&E Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	22	110	255	286	289
Commercial/Institutional	9	44	135	177	190
Residential	0	1	5	7	7
Cumulative Market Penetration, MW	31	155	395	470	487
Avoided Electric Cooling, MW	2	9	26	33	36
Scenario Grand Total	33	164	420	503	522
Annual Electric Energy (Million kWh)					
Industrial	174	868	2004	2245	2,269
Commercial/Institutional	55	276	831	1075	1,155
Residential	2	10	36	48	51
Total	**231**	**1,154**	**2,870**	**3,367**	**3475**
Avoided Cooling	6	29	79	100	107
Scenario Grand Total	237	1,183	2,949	3,467	3,582
CHP Fuel, (billion Btu/year)	2041	10,207	25,515	30,056	31,077
Avoided Boiler Fuel (Billion Btu/year)	583	2,917	7,160	8,450	8,721
Incremental Onsite Fuel (billion Btu/year)	1,458	7,290	18,355	21,606	22,356
Cumulative Investment (million 2011 $)	$41	$204	$513	$621	$623
Cumulative Capital Incentives(Million 2011 $)	$3	$16	$54	$70	$74
Annual Electric Energy (Million 2011 $)					
Total	**$18.84**	**$94.20**	**$266.55**	**$350.37**	**$385.80**
Avoided Cooling	$1.17	$5.85	$16.90	$22.58	$24.84
Scenario Grand Total	$20.01	$100.04	$283.44	$372.94	$410.64
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$12.05	$60.25	$159.85	$214.53	$246.26
Avoided Boiler Fuel	$4.90	$24.52	$62.70	$81.39	$90.86
Total	$7.15	$35.73	$97.15	$133.15	$155.40
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	1.8	8.8	32.7	49.1	53.9
500kW-1,000kW	1.4	6.8	23.6	32.2	34.2
1-5 MW	4.2	21.2	71.2	90.7	95.9
5-20 MW	4.3	21.6	57.5	68.8	72.7
>20 MW	19.3	96.4	209.7	228.7	230.3
Total Market	**31.0**	**154.9**	**394.7**	**469.5**	**486.9**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	25	125	238	168	166
Cumulative Avoided CO_2 Emissions, thousand MT	25	376	1,342	2,322	3,156
Average unit Emissions savings, lb/MWh	233.7	233.7	178.1	106.7	102.3
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	29	147	363	430	445
Cumulative Avoided CO_2 Emissions, thousand MT	29	440	1,823	3,841	6,036
Average unit Emissions savings, lb/MWh	273.4	273.4	271.6	273.7	273.6

Source: ICF International, Inc.

Table D-19: High Case SMUD Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	2	8	27	34	35
Commercial/Institutional	4	18	53	68	73
Residential	0	1	2	3	3
Cumulative Market Penetration, MW	5	26	82	105	112
Avoided Electric Cooling, MW	1	4	10	13	13
Scenario Grand Total	6	30	92	118	125
Annual Electric Energy (Million kWh)					
Industrial	11	57	195	245	254
Commercial/Institutional	20	102	297	376	402
Residential	1	4	14	19	20
Total	**33**	**164**	**506**	**640**	**676**
Avoided Cooling	2	10	27	34	36
Scenario Grand Total	35	174	534	674	713
CHP Fuel, (billion Btu/year)	327	1,637	4,954	6,208	6,550
Avoided Boiler Fuel (Billion Btu/year)	101	504	1,502	1,884	1,981
Incremental Onsite Fuel (billion Btu/year)	227	1,133	3,453	4,325	4,569
Cumulative Investment (million 2011 $)	$8	$42	$125	$160	$165
Cumulative Capital Incentives(Million 2011 $)	$1	$4	$16	$21	$22
Annual Electric Energy (Million 2011 $)					
Total	**$3.14**	**$15.70**	**$52.92**	**$72.75**	**$80.25**
Avoided Cooling	$0.26	$1.28	$3.70	$4.91	$5.38
Scenario Grand Total	$3.40	$16.98	$56.62	$77.66	$85.64
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$1.77	$8.86	$28.48	$41.02	$48.37
Avoided Boiler Fuel	$0.68	$3.42	$10.79	$15.22	$17.55
Total	**$1.09**	**$5.44**	**$17.69**	**$25.81**	**$30.82**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	0.3	1.7	7.8	12.4	14.0
500kW-1,000kW	0.4	1.9	7.0	9.7	10.4
1-5 MW	1.5	7.5	25.9	32.8	34.2
5-20 MW	2.2	11.0	33.1	40.5	42.9
>20 MW	0.8	4.2	8.7	9.7	10.1
Total Market	**5.2**	**26.2**	**82.4**	**105.1**	**111.5**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	3	14	23	-4	-4
Cumulative Avoided CO_2 Emissions, thousand MT	3	43	141	175	153
Average unit Emissions savings, lb/MWh	180.1	180.1	96.7	-14.1	-13.6
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	4	22	67	86	92
Cumulative Avoided CO_2 Emissions, thousand MT	4	65	309	702	1,150
Average unit Emissions savings, lb/MWh	273.2	273.2	276.7	282.8	283.4

Source: ICF International, Inc.

Table D-20: High Case Other North Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	8	42	116	139	146
Commercial/Institutional	1	6	19	25	27
Residential	0	0	0	0	0
Cumulative Market Penetration, MW	9	47	135	164	173
Avoided Electric Cooling, MW	0	1	3	4	5
Scenario Grand Total	10	48	138	168	177
Annual Electric Energy (Million kWh)					
Industrial	65	324	899	1076	1,131
Commercial/Institutional	7	34	108	142	153
Residential	0	0	1	2	2
Total	**72**	**358**	**1,009**	**1,220**	**1286**
Avoided Cooling	1	3	9	12	13
Scenario Grand Total	72	361	1,018	1,232	1,298
CHP Fuel, (billion Btu/year)	630	3,148	8,820	10,658	11,222
Avoided Boiler Fuel (Billion Btu/year)	204	1,019	2,793	3,382	3,555
Incremental Onsite Fuel (billion Btu/year)	426	2,129	6,027	7,276	7,667
Cumulative Investment (million 2011 $)	$12	$62	$168	$204	$206
Cumulative Capital Incentives(Million 2011 $)	$1	$4	$12	$16	$17
Annual Electric Energy (Million 2011 $)					
Total	**$5.59**	**$27.96**	**$86.24**	**$115.17**	**$129.05**
Avoided Cooling	$0.09	$0.47	$1.44	$2.00	$2.22
Scenario Grand Total	$5.69	$28.43	$87.68	$117.17	$131.27
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$3.38	$16.92	$50.35	$69.92	$82.30
Avoided Boiler Fuel	$1.32	$6.58	$19.06	$26.05	$30.15
Total	**$2.07**	**$10.34**	**$31.29**	**$43.86**	**$52.15**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	0.4	1.8	7.2	11.1	12.4
500kW-1,000kW	0.3	1.4	4.9	6.7	7.3
1-5 MW	1.0	5.2	17.5	22.0	22.9
5-20 MW	2.4	11.8	32.0	37.9	39.4
>20 MW	5.4	27.1	73.0	86.0	90.9
Total Market	**9.5**	**47.4**	**134.6**	**163.7**	**172.7**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	9	43	103	95	100
Cumulative Avoided CO_2 Emissions, thousand MT	9	130	524	1,013	1,501
Average unit Emissions savings, lb/MWh	264.3	264.3	222.4	169.2	169.3
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	10	49	139	170	179
Cumulative Avoided CO_2 Emissions, thousand MT	10	148	664	1,451	2,329
Average unit Emissions savings, lb/MWh	301.8	301.8	301.0	304.1	304.4

Source: ICF International, Inc.

Table D-21: High Case Other South Summary Output

CHP Measurement	2011	2015	2020	2025	2030
Cumulative Market Penetration (MW)					
Industrial	3	17	53	67	70
Commercial/Institutional	3	14	44	57	61
Residential	0	0	0	0	0
Cumulative Market Penetration, MW	6	31	98	124	131
Avoided Electric Cooling, MW	1	3	8	10	11
Scenario Grand Total	7	34	106	135	142
Annual Electric Energy (Million kWh)					
Industrial	24	121	384	483	501
Commercial/Institutional	19	94	287	368	393
Residential	0	0	0	0	0
Total	**43**	**215**	**671**	**851**	**894**
Avoided Cooling	2	9	25	32	34
Scenario Grand Total	45	224	697	883	927
CHP Fuel, (billion Btu/year)	438	2,190	6,646	8,346	8,749
Avoided Boiler Fuel (Billion Btu/year)	153	764	2,234	2,815	2,945
Incremental Onsite Fuel (billion Btu/year)	285	1,426	4,411	5,531	5,804
Cumulative Investment (million 2011 $)	$10	$49	$143	$183	$187
Cumulative Capital Incentives(Million 2011 $)	$1	$7	$23	$30	$32
Annual Electric Energy (Million 2011 $)					
Total	**$4.56**	**$22.79**	**$77.34**	**$105.68**	**$115.22**
Avoided Cooling	$0.27	$1.37	$4.03	$5.41	$5.94
Scenario Grand Total	$4.83	$24.16	$81.37	$111.09	$121.16
Incremental Onsite Fuel (million 2011 $)					
CHP Fuel	$2.58	$12.92	$41.56	$59.46	$69.20
Avoided Boiler Fuel	$1.05	$5.23	$16.18	$22.94	$26.33
Total	**$1.54**	**$7.69**	**$25.39**	**$36.52**	**$42.86**
Cumulative Market Penetration by Size and Year, MW					
50-500 kW	0.7	3.4	13.6	20.7	22.6
500kW-1,000kW	0.5	2.4	8.6	11.8	12.4
1-5 MW	1.9	9.6	32.3	40.4	41.9
5-20 MW	3.1	15.5	43.0	51.6	53.9
>20 MW	0.0	0.0	0.0	0.0	0.0
Total Market	**6.2**	**30.9**	**97.6**	**124.5**	**130.9**
Avoided CO_2 Emissions, Annual basis compared to RPS/C&T, thousand MT	4	20	34	-1	-1
Cumulative Avoided CO_2 Emissions, thousand MT	4	60	203	267	261
Average unit Emissions savings, lb/MWh	197.1	197.1	108.8	-3.7	-2.7
Avoided CO_2 Emissions compared to no policy case, Annual basis, thousand MT	6	30	93	121	128
Cumulative Avoided CO_2 Emissions, thousand MT	6	89	428	978	1,603
Average unit Emissions savings, lb/MWh	292.1	292.1	295.0	302.7	303.3

Source: ICF International, Inc.

Table D-22: Base Case Export Market Cumulative Market Penetration, MW

Time Period	Region/Size	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
2011	LADWP	0	0	0	1	5	6
	Other North	0	0	0	0	2	3
	Other South	0	0	0	1	0	1
	PG&E	0	0	2	9	44	56
	SCE	0	0	0	9	15	24
	SDG&E	0	0	0	1	12	13
	SMUD	0	0	0	1	0	1
	Total	0	0	3	22	79	104
2015	LADWP	0	0	0	2	9	11
	Other North	0	0	1	1	4	7
	Other South	0	0	0	3	0	3
	PG&E	0	0	8	25	44	77
	SCE	0	0	2	26	26	54
	SDG&E	0	0	1	3	22	26
	SMUD	0	0	0	3	0	3
	Combined Total	0	0	12	63	106	181
2025	LADWP	0	0	0	2	10	12
	Other North	0	0	2	1	5	8
	Other South	0	0	0	3	0	4
	PG&E	0	0	9	29	54	92
	SCE	0	0	3	31	28	62
	SDG&E	0	0	1	4	24	29
	SMUD	0	0	0	3	0	4
	Combined Total	0	0	16	74	121	210
2030	LADWP	0	0	0	2	10	13
	Other North	0	0	2	1	5	8
	Other South	0	0	0	3	0	4
	PG&E	0	0	10	29	54	93
	SCE	0	0	3	31	29	63
	SDG&E	0	0	1	4	24	29
	SMUD	0	0	0	4	0	4
	Combined Total	0	0	16	75	122	213

Source: ICF International, Inc.

Table D-23: Medium Case Export Market Cumulative Market Penetration, MW

Time Period	Region/Size	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
2011	LADWP	0	0	0	1	39	39
	Other North	0	0	0	0	18	18
	Other South	0	0	0	1	0	1
	PG&E	0	0	2	9	358	369
	SCE	0	0	0	9	111	121
	SDG&E	0	0	0	1	55	56
	SMUD	0	0	0	1	0	1
	Total	0	0	3	23	580	606
2015	LADWP	0	0	0	2	92	94
	Other North	0	0	1	1	43	45
	Other South	0	0	0	3	0	3
	PG&E	0	0	8	26	886	919
	SCE	0	0	2	27	265	294
	SDG&E	0	0	1	3	108	111
	SMUD	0	0	0	3	0	3
	Combined Total	0	0	12	65	1,393	1,470
2025	LADWP	0	0	0	3	102	105
	Other North	0	0	2	1	50	53
	Other South	0	0	0	3	0	4
	PG&E	0	0	9	29	992	1,031
	SCE	0	0	3	32	295	330
	SDG&E	0	0	1	4	116	121
	SMUD	0	0	0	3	0	4
	Combined Total	0	0	16	76	1,555	1,647
2030	LADWP	0	0	0	3	103	106
	Other North	0	0	2	1	52	55
	Other South	0	0	0	4	0	4
	PG&E	0	0	10	30	1,000	1,039
	SCE	0	0	3	33	297	332
	SDG&E	0	0	1	4	117	121
	SMUD	0	0	0	4	0	4
	Combined Total	0	0	16	77	1,568	1,661

Source: ICF International, Inc.

Table D-24: High Case Export Market Cumulative Market Penetration, MW

Time Period	Region/Size	50-500 kW MW	500kW-1,000kW MW	1-5 MW MW	5-20 MW MW	>20 MW MW	All Sizes MW
2011	LADWP	0	0	0	2	80	82
	Other North	0	0	1	1	27	29
	Other South	0	0	0	2	0	3
	PG&E	0	0	5	19	312	336
	SCE	0	0	3	24	192	219
	SDG&E	0	0	0	4	87	91
	SMUD	0	0	0	2	0	3
	Total	0	0	10	54	699	762
2015	LADWP	0	0	0	7	210	217
	Other North	0	0	3	4	73	79
	Other South	0	0	2	9	0	10
	PG&E	0	0	16	76	914	1,006
	SCE	0	0	10	86	505	601
	SDG&E	0	0	1	12	190	203
	SMUD	0	0	1	9	0	10
	Combined Total	0	0	33	202	1,892	2,127
2025	LADWP	0	0	1	8	236	245
	Other North	0	0	3	5	86	94
	Other South	0	0	2	11	0	13
	PG&E	0	0	20	93	1,043	1,155
	SCE	0	0	13	106	568	687
	SDG&E	0	0	2	14	207	223
	SMUD	0	0	1	12	0	13
	Combined Total	0	0	41	249	2,141	2,431
2030	LADWP	0	0	1	8	238	247
	Other North	0	0	3	5	91	99
	Other South	0	0	2	12	0	14
	PG&E	0	0	20	94	1,052	1,166
	SCE	0	0	13	108	573	693
	SDG&E	0	0	2	15	208	225
	SMUD	0	0	1	12	0	13
	Combined Total	0	0	41	254	2,162	2,458

Source: ICF International, Inc.

APPENDIX E: Workshop Comments and Response

The California Energy Commission held an *IEPR* Workshop on February 16, 2012. At this workshop ICF presented its findings contained in this report. The draft report was then docketed and made public under this proceeding, allowing for public comment to take place. Twelve organizations posted comments on the workshop; seven of these addressed the ICF report:

- California Cogeneration Council (CCC)
- California Large Energy Consumers Association (CLECA)
- Energy Producers and Users Coalition and the Cogeneration Association of California (EPUC)
- Pacific Gas and Electric Company (PG&E)
- Rita Norton & Associates, LLC (Norton)
- San Diego Gas & Electric Company (SDG&E)
- Southern California Edison Company (SCE)

The comments addressed the scope and focus of the report, assumptions, scenario definitions, logic of the analysis, and the results. This section summarizes these comments and provides the authors' response.

In review of this report for final publication, the Energy Commission identified one area it would like to comment on. The impact on rates resulting from costs associated with utilities implementing the 33 percent RPS is still being calculated. It is premature for ICF or anyone else to attribute rising utility rates and costs primarily to the RPS.

Comments on the Scope of the Analysis

- CLECA: The report does not include bottoming cycle CHP.
- Norton: The report does not include specific analysis of CHP opportunities in mixed use facilities — CHP as part of district heating and cooling systems. CHP potential is underrepresented by not including CHP in mixed use districts; additional state, local, and utility incentives and promotion; or inclusion of new business models of ownership and deployment.
- EPUC and CCC: The scope of the study was limited to evaluating CHP as a GHG reducing measure. Other public benefits of CHP should be considered, including grid

support, deferral of transmission and distribution investment, generation diversity, stimulation of in-state investment and economic activity, and energy efficiency.

- PG&E: Investor-owned electric utility companies were not given the early opportunity to provide input and comments. Comments and input were provided by a number of CHP advocacy groups, suggesting that the results are biased.
- SDG&E: The study states that GHG emissions reduction should be addressed on the basis of cost-effectiveness but provides no information on the cost of GHG emissions reduction.

Authors' Response

The analysis focuses on natural gas-fired CHP topping cycles. The exclusion of certain special types of CHP from the analytical framework was based on the difficulty of collecting data to identify opportunities for other types of systems and to generalize on the costs and performance for these other types of CHP systems. As shown in the report (**Figure 7**), 84 percent of existing CHP is fueled by natural gas. Analyzing the existing CHP more closely shows that 94.6 percent of CHP capacity added since 2000 is fired by natural gas or associated gas in the oil fields, 4.8 percent is fueled by biomass and biogas, and only 0.3 percent comes from waste heat-driven CHP bottoming cycles. While all sources of CHP are important, especially those that produce no GHG emissions themselves such as systems fueled by biomass and waste heat, the focus on natural gas systems is believed to capture close to 95 percent of the potential based on the trend analysis from the last 12 years.

As described at the workshop, district heating was not specifically included in the analysis, but the individual facilities that might comprise such systems were included.

The focus of the study was to estimate future CHP market penetration under existing policy measures and to define alternative cases that where market penetration could approach or exceed the *ARB Scoping Plan* goal. The motivation for the analysis was to identify how CHP contributes to the AB 32 program goals of GHG emissions reduction. Market penetration is based on the economics of CHP to the user, which were captured by the energy cost savings and the availability of other economic incentives. The study does not include an analysis of the values of all external benefits of CHP. However, some of the incentive measures are based on these other benefits, such as grid support and transmission and distribution deferral.

The comment by SDG&E that the report does not provide a basis for evaluating the cost effectiveness of CHP incentive options is valid. The Energy Commission requested a Base, Medium, and High Case to reflect a range of possibilities for CHP market penetration. To analyze the cost and benefit of each measure included in the scenarios would have required that the measures be analyzed one at a time, requiring the analysis of 15 cases rather than 3. This approach was discussed during the scoping for the project but was not pursued due to a combination of time and budget constraints and a desire to focus on the market penetration potential and not on prioritization of policy measures.

The authors do not believe that the process by which information, analysis, and results were developed and reviewed reflects bias on the part of either the authors or the Energy Commission as asserted by PG&E. PG&E, SCE, and SDG&E were interviewed regarding status and plans under the CHP QF Settlement Agreement during the project. The selection of reviewers for preliminary assumptions and outputs was made by the Energy Commission. In a study describing the results of a model that represents customer decision-making behavior with respect to CHP, it seems logical to focus on CHP experts and those representing groups of CHP operators. While the IOUs did not review these materials, the CPUC representing California IOU customers did participate in that review. The report is part of a larger collaborative process in which the IOUs are fully involved.

Comments on Assumptions

- CLECA: Near-term boiler gas price assumptions are too high, though the assumption of fixed real transportation costs is too low.
- CLECA: Electric transmission and distribution costs will escalate at a rate above inflation instead of remaining fixed in real terms as assumed in the study.
- CLECA: Pending rate cases will increase rates beyond what was assumed in the report.
- EPUC: The natural gas price assumptions are higher than others currently being used in the California regulatory environment.
- EPUC: The estimated equivalent full load operating hours (cited as 7,500) for CHP does not reflect the operating experience of the EPUC members that typically operate large CHP facilities at a 95 percent load factor.
- EPUC: The capital cost estimates for large CHP projects are low compared to the recent experience of EPUC members and compared to a 2009 Energy Commission analysis of generation costs.[70] Consequently the analysis overstates the economic viability of large scale CHP projects in California.
- PG&E: For boiler efficiency, ICF calculated the GHG benefit of CHP in both existing and new buildings by comparing it to a boiler of 80 percent efficiency. PG&E recommends that a higher boiler efficiency standard, at least 90 percent, should be used to estimate emissions from CHP in new buildings, because a developer's alternative is not an outdated boiler of merely 80 percent efficiency. Many firms now offer condensing boilers with efficiencies of 93 percent or better.
- SDG&E: The technical potential figures given for SDG&E in the report and in Appendix C do not match. (*Authors' note: Table C-7 plus C-8 show only the onsite technical potential from existing industrial and commercial facilities for SDG&E. The sum of these two tables equals*

70 Klein, Joel. 2009. *Comparative Costs of California Central Station Electricity Generation Technologies*, California Energy Commission, CEC-200-2009-017-SD.

*the existing on-site CHP potential shown in the report **Table 6**. The total CHP potential for SDG&E shown in **Table 20** is the sum of **Table 6** [existing on-site], **Table 10** [existing incremental export], and **Table 16** [facility growth 2011 – 2030*]).

- SCE: The assumption in the Medium and High Cases that over 20 MW pricing is based on MPR is an estimate only. Pricing will be set via competitive solicitations, which may be lower and/or higher than MPR. Following CPUC approval of the Qualifying Facility/CHP Settlement, the FERC relieved the California IOUs from the PURPA must-take obligation from QFs larger than 20 MW. Therefore, any assumptions including administratively set pricing for CHP larger than 20 MW are simply inconsistent with applicable law. (*Authors' note: the final text has been amended to include this clarification on page 110 of the report. The long-term export pricing assumptions, though based on administrative calculations of SRAC and MPR, were intended to represent alternative supply response points to market-based pricing.*)
- SCE: In SCE's experience, CCHP has only been cost-effective in very specific applications with a large, constant cooling need. SCE would like additional clarity regarding CCHP modeling and the underlying data behind ICF's operating assumptions.

Authors' Response

The several comments about the pricing assumptions were that the electric price assumptions were too low and the gas price assumptions were too high. Future prices are a key uncertainty in the analysis. The method used to estimate prices in the report was designed to be consistent with the Energy Commission's then ongoing Natural Gas Workshop mid case and the EIA *AEO 2011* Reference Case. Certainly, other price tracks are possible, and these other prices would affect future CHP market penetration. If there were a fundamental shift in the relationship between gas and electric prices as suggested by the commenters, then CHP penetration would be higher than shown in the report.

The report assumption that electric transmission and distribution prices will be constant in real dollars does not imply that there will be no future transmission and distribution investments. It implies that investment will increase at the rate of inflation. The EIA *AEO 2011* analysis showed transmission and distribution costs for California declining in real terms. The report assumption that it will remain constant in real dollars was a departure from the EIA assumption. Real escalation in electric transmission and distribution would increase electric prices and stimulate additional CHP deployment. However, there is a similar argument that natural gas transmission and distribution costs will need to increase to cover the costs of mandatory inspection and potential replacement of transmission lines.

Regarding the comment on boiler efficiency, CHP systems would replace boilers that are much larger than the condensing tankless water heaters cited by PG&E. The smallest discrete boiler replacement that is modeled is for a 275 kW CHP system replacing a 1.7 MMBtu/hour boiler. The average combustion efficiency for all gas-fired boiler products for sale in California is 82.5 percent for water boilers and 80.6 percent for steam boilers.[71] These average efficiencies do not include the high-pressure steam boilers commonly used in large industrial applications. The rationale for choosing 80 percent as the comparative boiler efficiency is that the economic calculation is based on the savings compared to existing boilers, not the best new boiler that the customer could buy. Since the comparison is to the existing boiler equipment, the economic calculation takes no capital cost credit for the avoided cost of a new boiler. Increasing the efficiency of avoided boiler output to 90 percent for all market segments would decrease the Base Case 20-year market penetration by 9 percent. Restricting this increase in boiler efficiency to market segments less than 5 MW, a more realistic scenario, reduces 20-year market penetration by 6 percent.

EPUC commented on operating hours and capital costs for large CHP. The equivalent full load hours for high load factor CHP in the analysis ranges from 7,008 to 8,059, depending on system size. The large systems greater than 20 MW define the high end of that range representing a 92 percent load factor that is very close to the recommended 95 percent. Higher load factors would produce greater market penetration and GHG savings, but the difference in market penetration resulting from such a small change would be under 3 percent.

The large CHP system capital cost assumptions selected for the analysis were based on recent study estimates for large gas turbine CHP systems. The analysis numbers are consistent with estimates in the *2011Draft MPR* used for large gas turbine combined cycle plants and with estimates for gas turbine simple and combined cycle plants used in the EIA *AEO 2011* forecast. However, if the EPUC concern that quotes for new projects in California are much higher than these estimates, then these higher costs need to be considered in future work, not only regarding the cost for new CHP but also regarding the cost for new competing gas turbine power plants and for the MPR calculation. New CHP plants in the range of $1,900 – $3,000/kW with 18 – 25 percent annual carrying costs would not be competitive against the *2011 Draft MPR* based on the assumption of an average capital cost of $1,136/kW and an as calculated annual carrying charge of 14.8 percent. On the other hand, if large gas turbine CHP plant capital costs will be in the range of $1,900-$3,000/kW, then new electric combined cycle capacity will be similarly much higher than the *2011 Draft MPR* estimate of $1,136/kW.

EPUC also commented that the 40 MW gas turbine CHP plant cost estimates used in the report appear inconsistent with a recent Energy Commission report on electric generation technology capital and operating costs.[72] EPUC questioned why the 2009 study estimated a capital cost for a 49 MW simple cycle gas turbine of $1,292/kW in 2009 while the present analysis gave an estimated cost of $1,254/kW for a 40 MW gas turbine CHP system. First, ICF's 2009 *CHP Market Assessment Report* notes that there is a wide range of prices. Its own

71 Appliance Efficiency Database, California Energy Commission, http://www.appliances.energy.ca.gov/.

72 Ibid. 68.

low-to-high capital cost range for the small gas turbine was $914-$1,578/kW. Secondly, EPUC is comparing the wrong number to ICF's 2009 *CHP Market Assessment Report*. In this study, as shown in **Table 40**, the capital cost of the 40 MW gas turbine with emissions after treatment is $1,323/kW before adjusting for investment tax credit and the SGIP. The team's analysis of the costs of adding the heat recovery equipment is about $90/kW. ICF's 2009 *CHP Market Assessment Report* also shows that cost escalation for gas turbine plants reversed in 2008 and costs came down for 2009, so there is not an automatic conclusion that the current costs should be higher.

The comparison that EPUC makes between the "levelized cost estimates" compares the implied levelized capital charge used in the team's report with a figure from ICF's 2009 *CHP Market Assessment Report* that includes capital charges, ad valorem taxes and insurance, income taxes, and fixed O&M costs. The team's net power cost estimate was intended to provide a simple comparison among technologies. As such, the calculation may be somewhat misleading. It does not include income taxes, ad valorem taxes, or insurance. These costs would add about 2 cents/kWh to the net power costs shown in this report for a merchant plant. The net power cost calculation was not used as the basis for analyzing the economic value of the technology. Economic value and market penetration in the model are based on payback period.

Regarding clarification of the assumptions used in the thermal cooling markets. The assumptions regarding capital cost are shown in the 2011 ICF *CHP Market Assessment Report* (pages 101-102). The efficiency of thermal cooling depends on the quality of thermal energy available from the particular CHP technology and is either set at a coefficient of performance of 0.7 for low temperature waste heat or 1.1 for high-temperature waste heat. The avoided electric cooling efficiency was assumed to be 0.68 kW/ton of cooling. The application analysis assumes that half of the thermal energy is devoted to cooling and half to boiler loads. In the analysis avoided, electric cooling represents only 5 – 8 percent of the scenario capacity and 2 – 4 percent of the scenario electricity generated/avoided.

Comments on Scenarios

- CCC: The ICF report could be improved through the addition of a high gas price scenario for CHP development, and suggests a high gas price case that is 20 percent higher than that used by ICF. Such a scenario would underline the importance of CHP as a hedge against future unexpected increases in fossil fuel prices.
- CLECA: There is no basis for the blanket inclusion of a $50/kW-year transmission and distribution investment deferral incentive for all CHP. The benefits are site-specific.
- SDG&E: A supply curve approach to providing GHG savings would be more useful than the scenario approach.

- SDG&E: Combined cycle technology should not be part of the high case export scenario. CHP estimates should be based on meeting thermal loads, not maximizing power generation.
- SDG&E: The characterization of GHG allowance cost exposure for all CHP is disputed. There will be cases where these costs would not be applied in cases of expansion in trade-exposed industries or in small customers that might receive relief from gas suppliers.

Authors' Response

The selection of measures and characterization of those measures for each scenario was an interactive process involving the project team, the Energy Commission, and selected reviewers. The only comment that applies to the Base Case is the treatment of cap-and-trade allowances. This is one assumption for which a detailed sensitivity analysis was conducted to identify the effect of alternative assumptions.

The other comments apply to the alternative (Medium and High) cases or to additional cases that the commenters wanted to see.

Given the uncertainty of future gas and electric pricing, alternative price cases or sensitivity analysis on the impact of changing prices could improve future work in this area. One difficulty in looking at alternative prices is that electric prices are related to gas prices in a fairly complex way. Higher or lower gas prices affect both average and marginal electric prices, so it is important when changing gas price assumptions to maintain the relationship with electric pricing.

The authors understand that the value of CHP for grid support and transmission and distribution investment deferral is highly site-specific. The ICF California CHP model is not currently configured in a way to identify and model constrained areas separately. The selection of an across the board $50/kW annual transmission and distribution deferral value was intended to approximate the effect having a program in place that was based on local attributes. A recent analysis by E3 shows that transmission and distribution deferral benefits vary from more than $400/kW-year to zero.[73] This work was reviewed before selecting the approximation of $50/kW-year, which value was seen as being consistent with recent work undertaken for the CPUC by E3 in its energy efficiency and distributed generation calculators. [74]

The purpose of the assumption that the large export market would be based on combined cycle power plant technology in the High Case was to show how much additional electric power could be produced under that scenario. There are large CHP plants in operation that

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73 *Attachment D: Energy and Environmental Economics Detailed Description of Location Cost Adder*, R.11-05-005, CPUC, October 13, 2011.

74 Private Communication, Tom Beach, Crossborder Energy, January 25, 2012.

are based on combined cycle technology. However, the purpose of including it in the High Case was not to present a recommended or most likely strategy.

The decision to bundle policy measures together into Base, Medium, and High Case scenarios does not provide information on the comparative impacts and costs for each individual measure as would be possible with a supply curve approach. The deconstruction of the three scenarios into analysis of individual measures cannot be provided under the scope of the current contract but could be addressed in a subsequent task.

Comments on Analytical Logic

Several comments pertain to the analytical logic used in developing the project results. These comments cover a wide range of topics. The authors' responses are added in parentheses at the end of each comment below:

- CCC: The GHG analysis under RPS that shows declining benefits implicitly assumes the complete success of all other GHG reducing measures and ignores the economic value of including CHP as a GHG reducing measure. Over time the goals need to be periodically re-evaluated. *(The analysis used the grid electricity values from the* ARB Scoping Plan *in order to provide a direct comparison to the Scoping Plan goal for CHP. It is true that over time, both the average and marginal utility sector unit emissions rates should decrease if the Cap and Trade and RPS goals are being met. Decisions regarding incentives for additional CHP deployment or additional CHP request for offers should be updated to take into consideration the progress toward emissions reduction and the relative costs of achieving further reductions.*
- CLECA: The methodology used to identify the avoidable electric costs for on-site CHP is not valid in that it is based on the marginal cost of power from a combined cycle power plant and it does not include the cost impacts of adding renewables for RPS. (*The avoidable power costs are based on the structure of current tariffs and the expected performance of CHP. The long-term movement of prices is tied to the cost of power from a combined cycle power plant but with the inclusion on top of that of the added costs associated with RPS as defined in the CPUC/E3 GHG calculator.*)
- PG&E: ICF's CHP adoption curves are very aggressive and, as a result, may overstate the potential to add CHP to the system, particularly in the current economic environment. (*The market acceptance curves used for the analysis [shown in* ***Figure 33***] *were based on survey data of California customers as described in the report. The average acceptance curve used for most sectors shows that only 50 percent of customers would accept a 2-year payback. The authors consider this to be a very risk-averse behavior that is anything but aggressive. The strong prospects curve that is used for the greater than 20 MW market is more aggressive. This function was developed in conjunction with the CHP users groups during the* 2009 ICF Market Assessment *study.)*
- PG&E: ICF bases its technical potential analysis on usage patterns and business type, but ignores physical barriers, such as space limitations or age of the building, and ignores

any non-economic factors, such as availability of air permits or zoning restrictions. ICF's assumptions on load factors and thermal usage do not reflect real-world analyses of CHP installations from the SGIP and QF programs. PG&E believes that the ICF methodology generally overestimates technical potential. *(The technical potential methodology used in the report is based on aggregate customer characteristics by business line. Real customer specific variations that PG&E mentions are not analyzed directly due to limitations in the data. The maximum market penetration rates for each size class are used to qualitatively reflect these factors by removing a percentage of the technical potential from the market acceptance calculation. These factors are shown in* ***Table 53*** *of the report.)*

- EPUC: The ICF approach for determining technical market potential does not take into account the age of boiler equipment. In particular, the methodology used to quantify the potential in the enhanced oil recovery sector is overstated due to recent deployment of new boilers in a number of fields. *(It is true that the approach used in the analysis does not identify potential based on boiler age, and it is true that when boilers need to be upgraded or replaced, it is an excellent time to consider installing a CHP system. However, it is common for CHP systems to rely on existing boiler capacity when the CHP system is not operating, and economic CHP investments can be made regardless of the age of existing boilers. EPUC did provide guidance to the study team in identifying public sources of information on steam use in the California oil fields, but, due to confidentiality issues with its members, could not provide the type of information on boiler investments and operator decision making upon which it asserts that the estimate should be based.)*
- SDG&E: There is no justification provided for the use of higher participation rates for larger size bins than smaller size bins. (*Because the technical potential estimation procedure does not include non-economic and site-specific factors as noted in PG&E's comments, the maximum participation factors are used to reduce potential issues of overestimation — issues considered to be more severe in the smaller size bins. The inputs reflect the authors' judgment about the sum of factors, not measured, that would disqualify CHP from consideration at a site.)*
- SDG&E does not agree with changing the maximum market participation rates by scenario to reflect changes in behavior. *(Using these factors to reflect change in customer risk perception and willingness to consider CHP by scenario was not used in the 2005*[75] *or 2009 California CHP market studies. Its use in this way was first recommended by consulting staff for the Department of Energy Mid-Atlantic Clean Energy Applications Center for a study of critical CHP policy measures in key states.*[76] *The intent is that the economic payback and market acceptance calculations reflect the economic effect and the change in the maximum market participation factors reflects behavioral change.)*

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75 Petrill, Ellen; Rastler, Dan. 2005. *Assessment of California CHP Market and Policy Options for Increased Penetration,* California Energy Commission, CEC-500-2005-060-D.

76 Consulting Staff to the Mid-Atlantic Clean Energy Applications Center, Gearoid Foley and Richard Sweetser, Private Communication, August 2010.

- SDG&E: ICF's approach to estimating useful thermal energy as a function of size is incorrect. *(The CHP sizing decision and the amount of thermal energy used varies site by site. The report simply tries to generalize that larger systems, whether they are strictly using power onsite or a mixture of onsite and export, have a higher thermal usage rate than smaller systems.)*
- SDGE: The market penetration estimates in **Table ES-2** should be redefined as customer acceptance values because it takes a number of years from the time a project is accepted until it is constructed and on-line. *(Appendix A, page A-8, describes that a diffusion curve is used to determine how much of the market acceptance share enters the market during a given period. This diffusion curve is intended to address the delay between the determination that a quantity of CHP is economic and the rate at which it enters the market.)*
- SDG&E: The assumption that export GHG does not displace renewable generation is incorrect and provides the incorrect conclusion that export CHP is "cleaner." *(The distinction is meant only to reflect that exported CHP electricity figures into the utility's capacity and GHG emissions. If more natural gas-fired CHP is added to the utility's supply mix, more renewable energy must be found to meet the RPS goals. Therefore, exported CHP competes with the utility's other fossil sources. CHP behind the meter reduces the utility's electric demand, thereby reducing its renewable requirement proportionally. The report does not address the ability of electric utilities to absorb the CHP export quantities in each scenario and still meet RPS and cap-and-trade requirements. The scenarios only show how much CHP would be offered.)*
- SCE: The use of aggregate electrical and thermal profile assumptions will overstate modeled operating efficiencies and thus, overstate potential GHG savings. There are significant differences within customer classes. As incentives for CHP increase, less efficient CHP systems will become economic and enter the market. The use of average load factors and thermal use rates does not capture this effect and thereby overestimates the GHG emissions savings improvement of the medium and high case scenarios. *The average assumptions used for electric load factor and thermal usage rate are considerably below a best practices value and below the assumptions used in the* ARB Scoping Plan *calculation. Therefore, the authors feel that these averages do not overestimate the economics or the GHG savings.)*
- SCE: The cumulative incentive costs reported on page 124 are understated because they include only the cost of the SGIP and the 10 percent investment tax credit in the High Case. These figures should also include the incremental cost of "MPR" relative to SRAC pricing or a measure of market pricing, the redistribution of departing load charges and standby charges to nonparticipating customers, and the $50/kW-yr transmission and distribution capacity deferral payment, which is assumed without any justification or basis. Additionally, the High Case adjustments to CHP capital costs and the market acceptance model make it impossible to draw any policy conclusions from this scenario. *(The primary policy conclusion from the study is that California is not going to meet either the CHP market penetration or GHG savings target described in the* ARB Scoping Plan *with the policies that are currently in place. SCE is right that the study does not provide all of the information needed to prioritize the costs and benefits of the additional measures included in the*

Medium and High Cases. Regarding specific measures mentioned, the MPR pricing is only an estimate of the bid price that would produce a higher level of CHP procurement, which would be based on the utility's overall long-term planning process and not supported by transfer payments from other customers. A transmission and distribution deferral payment should be designed to be supported by the deferred transmission and distribution costs and not by other customers. The proposed measure to exempt CHP generation from nonbypassable charges would reduce utility collections for Public Interest Energy Research, Renewable Energy Program, Energy Efficiency, and California Alternative Rates for Energy. However, it is not clear whether funding reductions would be made up from existing customers or new electric demand growth over the 20-year forecast period. In addition, the underlying issue is that energy efficiency and renewable energy projects do not pay these departing load charges on their generated/avoided energy.)

- SCE: The ICF Base Case assumes AB 1613 pricing for all units 20 MW and smaller. This is not accurate as it is likely that there will be a mix of 20 MW and under generators in the AB 1613 program and the PURPA program. Additionally, the description of AB 1613 on page 15 of the report appears to be incorrect. The description seems to imply that only CHP facilities of nonprofit organizations are allowed to participate in the AB 1613 program; this is not the case. *(The description of the AB 1613 program on page 15 has been amended. The assumption that all under-20 MW export potential would participate in AB 1613 is a simplification. Using the estimated AB 1613 tariffs, market penetration for this sector is very low. Showing a portion of this market competing at the lower SRAC pricing would only lower this penetration further.)*

Comments on Results

- PG&E: The report overestimates the potential for CHP particularly for existing small customers.
- EPUC: The report overestimates the potential for large CHP due to the underestimation of capital costs.
- SDG&E questions having "must take" CHP part of the power generation landscape in 2050.
- SCE: The statement on page 127 that "CHP would save customers $740 million per year in energy costs under the Base Case and $2.9 billion per year under the High Case" should be changed to refer to participating customers unless sufficient analysis is done to estimate the costs borne by non-participating customers to create these savings. *(Authors' note: Text amended on page 127 as suggested.)*

Authors' Response

PG&E and EPUC note that CHP market penetration results are too high. Other comments on the assumptions would have a mixed effect on the results. Recommended changes to pricing assumptions and to the assumptions regarding the treatment of GHG allowance costs for CHP users would increase market penetration compared to the report results. Increase in the competitive boiler efficiency and increase in CHP capital costs would lower market penetration. While not in a position to rerun all of the analysis based on the comments received, the authors' *a priori* estimate would be that the sum of the recommended changes would result in somewhat lower market penetration estimates. The largest negative factor is the apparent shift in CHP capital costs. However, as noted, higher capital costs would affect the outlook for future utility costs and future renewable energy systems offsetting some or all of the direct effect of more costly CHP.

The electric utility commenters, in one way or another, all questioned the value of adding CHP to the supply mix that would, in the later part of the forecast period, interfere with their ability to meet lower and lower GHG emissions goals through other means. This report only looks at the likely CHP market penetration and factors that could stimulate CHP market penetration given exogenous assumptions about electric costs and pricing. Approaches that look at long-term electricity supply and demand typically treat CHP in a very rudimentary fashion, if at all. Evaluating how CHP fits into the long-term procurement planning for utilities under cap and trade and the 33 percent RPS would require integration of the ICF CHP Market Model with both electric sector supply and demand modeling. While beyond the scope of the current study, such an integrated approach could provide a better view of factors such as the GHG allowance clearing price, the cost and adoption of renewable energy systems, and energy efficiency, and the combined effect of all the alternative options on the long term cost of power generation, transmission, and distribution.