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Encouraging Combined Heat and Power in California Buildings

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Disclaimer

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Of course, the authors alone are responsible for the contents of this report.

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ABSTRACT

Governor Brown's research priorities include an additional 6.5 GW of combined heat and power (CHP) by 2030. As of 2009, roughly 0.25 GW of small natural gas and biogas fired CHP is documented by the Self-Generation Incentive Program (SGIP) database. The SGIP is set to expire, and the anticipated grid de-carbonization based on the development of 20 GW of renewable energy will influence the CHP adoption. Thus, an integrated optimization approach for this analysis was chosen that allows optimizing the adoption of distributed energy resources (DER) such as photovoltaics (PV), CHP, storage technologies, etc. in the California commercial sector from the building owners' perspective. To solve this DER adoption problem the Distributed Energy Resources Customer Adoption Model (DER-CAM), developed by the Lawrence Berkeley National Laboratory and used extensively to address the problem of optimally investing and scheduling DER under multiple settings, has been used. The application of CHP at large industrial sites is well known, and much of its potential is already being realized. Conversely, commercial sector CHP, especially those above 50 to 100 kW peak electricity load, is widely overlooked. In order to analyze the role of DER in CO_2 reduction, 147 representative sites in different climate zones were selected from the California Commercial End Use Survey (CEUS). About 8000 individual optimization runs, with different assumptions for the electric tariffs, natural gas costs, marginal grid CO_2 emissions, and nitrogen oxide treatment costs, SGIP, fuel cell lifetime, fuel cell efficiency, PV installation costs, and payback periods for investments have been performed. The most optimistic CHP potential contribution in this sector in 2020 will be 2.7 GW. However, this result requires a SGIP in 2020, 46% average electric efficiency for fuel cells, a payback period for investments of 10 years, and a CO_2 focused approach of the building owners. In 2030 it will be only 2.5 GW due to the anticipated grid de-carbonization. The 2030 result requires a 60% electric efficiency and 20 year life time for fuel cells, a payback period of 10 years, and a CO_2 minimization strategy of building owners. Finally, the possible CHP potential in 2030 shows a significant variance between 0.2 GW and 2.5 GW, demonstrating the complex interactions between technologies, policies, and customer objectives.

Keywords: distributed energy resource modeling, combined heat and power, CHP, combined cooling, heating, and power, CCHP, commercial buildings, fuel cells.

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1 Acronyms and Abbreviations

$/kWh$_t$	US Dollars per kWh thermal
AB 32	Assembly Bill 32 (the Global Warming Solutions Act)
AEO	Annual Energy Outlook
bln $	billion US Dollars
CAA	Clean Air Act
CAISO	California Independent System Operator
Cal/EPA	California Environmental Protection Agency
CARB	California Air Resources Board
CCHP	combined cooling, heating, and electric power
CEUS	California Commercial End-Use Survey
CHP	combined heat and power
CSI	California Solar Initiative
CPP	critical peak pricing
DER	distributed energy resources
DER-CAM	Distributed Energy Resources Customer Adoption Model
gCO_2/kWh$_e$	grams of CO_2 per kWh electricity, 1 gram = 1/1000 kg
DG	distributed generation
EECC	electric energy commodity cost (for SDG&E)
FC	fuel cell
GHG	greenhouse gas
GW	Giga Watt = 10^9 Watt
HX	heat exchanger
ICE	internal combustion engine
IOU	investor owned utility
kgCO_2/kWh	kilogram CO_2 per kWh
kt/a	1000 metric tons of CO_2 per year
kW	kW = 10^3 Watt
kW$_e$	kW electricity
kW$_t$	kW thermal
LADWP	Los Angeles Department of Water and Power
LBL, LBNL	Lawrence Berkeley National Laboratory
MT	micro-turbine
mln $	million US Dollars
MPR	market price referent
MRR	Mandatory Reporting Regulation (GHG reporting to US EPA and Cal/EPA for entities emitting over 25,000 mtCO_2e annually)
Mt/a	metric tons per year
mtCO_2e	metric tons of CO_2 equivalent (emissions)
MW	Mega Watt = 10^6 Watt
NERC	North American Electric Reliability Cooperation

PDP	Peak Day Pricing
PG&E	Pacific Gas and Electric
PEMFC	Proton Exchange Membrane Fuel Cell
ppm	parts per million
ref.	refrigerated
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SoCalGas	Southern California Gas Company
SGIP	Self-Generation Incentive Program
SOFC	Solid Oxid Fuel Cell
SUMD	Sacramento Municipal Utility District
TOD	time of delivery
TOU	time of use
US EPA	United States Environmental Protection Agency
Unref.	unrefrigerated
ZNEB	zero net energy building

2 Background

2.1 Introduction

Governor Brown's Research Priorities in the areas of Clean Energy and Energy Efficiency call for the development of 20 GW of renewable energy, including 12 GW of distributed renewable generation by 2020. Furthermore, aggressive building and appliance efficiency standards, including targets for zero net energy homes and businesses, new financing tools to incentivize widespread energy retrofits of existing buildings, development of energy storage to meet peak load demand and to provide flexible power to help integrate renewables are pursued by the California Energy Commission (CEC) as well as the California Public Utilities Commission (CPUC). Brown's agenda also includes an additional 6.5 GW of combined heat and power (CHP) by 2030 (Neff, 2012). As of 2009, roughly 250 MW of small natural gas and biogas fired CHP is documented by the Self-Generation Incentive Program (SGIP) database. SGIP is set to expire soon and this raises the question: taking into consideration the interactions of distributed energy resources (DER) including CHP, how can the additional 6.5 GW of CHP be easily reached? It is not possible to see CHP in isolation since it generates electricity and heat, which can be utilized for heating or cooling purposes. Thus, an integrated optimization approach for this analysis was chosen that allows optimizing the adoption of the following technologies in the commercial sector:

- fuel cells, with and without heat exchanger for waste heat utilization
- internal combustion engines, with and without heat exchanger for waste heat utilization
- micro turbines, with and without heat exchanger for waste heat utilization
- gas turbines, with and without heat exchanger for waste heat utilization
- photovoltaic
- solar thermal
- electric storage
- heat storage
- absorption chillers
- zero net energy homes; since zero net energy homes will play a role in the future. The used optimization tool, the Distributed Energy Resources Customer Adoption Model (DER-CAM), also allows simulating the impact of such zero net energy homes on CHP adoption.

The application of CHP at large industrial sites is well known, and much of its potential is already being realized (Darrow et al., 2009). Conversely, commercial sector CHP, especially in the building range between 100 kW to 5 MW electric peak load, is widely overlooked. Assuming a maximum DER unit size of 3.5 MW, roughly 235 MW of CHP capacity is currently installed in commercial buildings based on the combined heat and power database from EEA, 2012. Buildings include commercial facilities as office buildings, colleges, hospitals, healthcare, office buildings, restaurants, etc. Well recognized candidates for CHP installations are hospitals, colleges, and hotels because of the balanced and simultaneous requirements for electricity and heat for hot water, space heating, and cooling. But, other buildings, such as large office structures, can also favor CHP, often with absorption chillers that use waste heat for cooling (Stadler et al., 2009 and Marnay et al., 2008). Based on the CEUS database, which contains 2790 premises, the role of distributed generation (DG) and CHP in greenhouse gas (GHG) abatement is determined. Since it is computationally expensive to solve multiple buildings, 147 representative CA sites[1] in different climate zones were picked. Together, these sample buildings represent roughly 37% of CA commercial electricity demand. Simulating these selected buildings requires a total DER-CAM run time of less than 12 hours, which allowed for multiple sensitivities. For this research, more than 50 sensitivity runs[2] with different technology costs, tariffs, de-carbonization levels of the macro-grid, etc. have been performed.

2.2 Objectives of this work

The goal of task 2.8 of CEC-500-10-052 is to simulate economic and environmentally sound natural gas-fired combined heat and power and combined cooling, heating, and electric power (CCHP) adoption in California's medium sized commercial building sector.

Thus, key project objectives are:

- perform optimization runs for 2030 and update existing 2020 runs from Stadler et al., 2010
- develop multiple scenarios that reflect grid de-carbonization, changes in equipment performance, and regulatory environment; besides CO_2 emissions NOx emissions are also considered in the DER-CAM runs
- consider zero net energy buildings and their impact on CHP and CCHP
- consider feed-in tariffs
- put a special focus on the California restaurant sector since it is a major consumer of natural gas and was partly neglected in the predecessor project (see also Stadler et al., 2010).

Please note that in 2009 and 2010 a predecessor project was executed which focused on commercial buildings with electric peak loads between 100 kW and 5 MW, leading to the neglect of almost all restaurant buildings from the CEUS database. That project reported on 2020 results and this follow-up project now takes restaurants into account, updates the results for 2020 and performs new runs for 2030.

2.3 Structure of this final report

Task 2.8 "Encouraging Combined Heat and Power in California Buildings" started on January 1st 2012 and four extended memorandums have been delivered so far:

- Data Collection Memorandum, January 30th 2012
- Forecasts and Scenarios Memorandum, February 28th 2012
- Basic Results of DER-CAM Simulation Memorandum, May 31st 2012

[1] Hospitals, colleges, schools, restaurants, warehouses, retail stores, groceries, offices, and hotels in different sizes.

[2] This number also includes calibration runs.

- Site Analyses and Restaurant Analysis Memorandum, July 31st 2012

All these memorandums had an extended scope and reported in detail on the results achieved by the delivery date. This final report builds on these four extended memos and summarizes the most important results and all four extended memos can be found in the appendix of this report. In other words, information and data already presented in the four extended memorandums, such as tariffs and technology data, are not covered in detail in the main body of this report but are referenced and in the appendix.

The structure of this report is as follows:

- Chapter "DER-CAM" describes the Distributed Energy Resources Customer Adoption Model (DER-CAM)
- Chapter "Data sources" discusses the California Commercial End-Use Survey (CEUS), electric tariffs and natural gas prices, marginal CO_2 emissions from the utility, NOx emissions and treatment costs, technology costs, as well as the assumptions for SGIP and feed-in tariffs briefly
- Chapter "Optimization runs" describes all major optimization runs. This chapter starts with a description of all major optimization runs and shows the high level CHP results, before explaining the results in more detail. If the reader is only interested in the high level CHP results she/he can skip chapter 5.3 (Detailed optimization results).
- Chapter "Results for the restaurant sector" discusses the restaurant sector specific results
- Chapter "High level comparison of 2020 and 2030 results" describes the major difference between the 2020 and 2030 results.
- Chapter "Impact of building stock growth" estimates the impact of building stock growth compared to CEUS, which is based on 2006 data.
- Chapter "Conclusions" summarizes the paper and discusses the policy impacts
- Chapter "Appendix" holds additional information and figures as well as the extended memorandums delivered so far.

This structure is used due to the huge amount of optimization runs performed within this project. About 50 different run sets (equal to about 8000 individual optimization runs or 600 hours of pure optimization time) with different assumptions for the tariffs, natural gas costs, marginal grid CO_2 emissions, and nitrogen oxide (NOx) treatment costs for internal combustion engine (ICE), Self-Generation Incentive Program (SGIP), fuel cell lifetime, fuel cell efficiency, PV installation costs, and maximum payback period have been performed in this project.

3 DER-CAM

This analysis was not done in isolation and considers other DER technologies as PV, solar thermal, electric and heat storage, which can be in competition with CHP and CCHP or supplement each other, depending on the building type and DER adoption strategy.

DER-CAM is a Mixed Integer Linear Programming (MILP) model developed by the Lawrence Berkeley National Laboratory and used extensively to address the problem of optimally investing and scheduling DER under multiple settings. Its earliest development stages go back to 2000 (Marnay et al., 2000), and stable versions can be accessed freely by the general public using a web interface (DER-CAM Website, 2012). Along with HOMER (Homer Energy, 2012), formerly developed by the National Renewable Energy Laboratory, it is one of the few optimization tools of its kind that is available for public use. It has been continuously improved to incorporate new technologies and features, and used in several peer-reviewed publications (Siddiqui et al., 2005), (Marnay et al., 2008). Recently, it has also been updated to incorporate electric vehicles (Momber et al., 2010 and Stadler et al., 2012). An improvement of DER-CAM to be able to consider passive improvements such as adding wall insulation or window changes is available soon and a publication is currently being prepared.

Two main versions of DER-CAM have been developed: Investment & Planning DER-CAM, and Operations DER-CAM. Operations DER-CAM is available only for scientific purposes and not for the general public. Investment & Planning DER-CAM, which is used in this work, picks optimal micro-grid[3]/building equipment combinations based on either 36 or 84 typical days representing a year of hourly energy loads and technology costs and performance, fuel prices and utility tariffs. Operations DER-CAM deals with the optimal dispatch in a micro-grid or building for a given period, typically a week ahead, with a time resolution of 5 min, 15 min, or 1 h, assuming the installed capacity is known and using weather forecasts from the web to forecast requirements.

DER-CAM's objective is typically to minimize the annual costs or CO_2 emissions for providing energy services to the modeled site, including utility electricity and natural gas purchases, plus amortized capital and maintenance costs for any DG investments. Other objectives, such as carbon or energy minimization, or a combination are also possible. The approach is fully technology-neutral and can include energy purchases, on-site conversion, and both electrical and thermal on-site renewable harvesting. Furthermore, this approach considers the simultaneity of results. For example, building cooling technologies are chosen such that the results reflect the benefit of electricity demand displacement by heat-activated cooling, which lowers building peak load, and therefore, the on-site generation requirement, and also has a disproportionate benefit on bills because of demand charges and time-of-use (TOU) energy charges.

The key inputs in Investment & Planning DER-CAM are:

- hourly electricity, heating, cooling, domestic hot water, and cooking demand for the selected representative commercial buildings; the building load profiles within this project are taken from the California Commercial End-Use Survey (CEUS, 2006) and have been modified and formatted to fit DER-CAM
- electric and natural gas tariffs

[3] A *micro-grid* is herein defined as a cluster of electricity sources and (possibly controllable) loads in one or more locations that are connected to the traditional wider power system, or *macro-grid*, but which may, as circumstances or economics dictate, disconnect from it and operate as an island, at least for short periods. Please note that micro-grids can consist of multiple buildings/locations or just of a single building/location and in this work micro-grids are considered to be a single building.

- technology performance data and costs for the selected DER technologies
- CO_2 emissions of the macro-grid to assess the CO_2 mitigation potential of CHP and CCHP and other DER
- solar radiation for different locations in California to be able to consider the impact of PV and solar thermal on CHP/CCHP adoption.

Figure 3-1 shows a high-level schematic of the possible building energy flows modeled in DER-CAM. For this we use Sankey diagrams, which show in a graphical way how loads can be met by different resources at given efficiencies. Thus, a Sankey diagram provides a full view of possible resources that can be considered within the optimization.

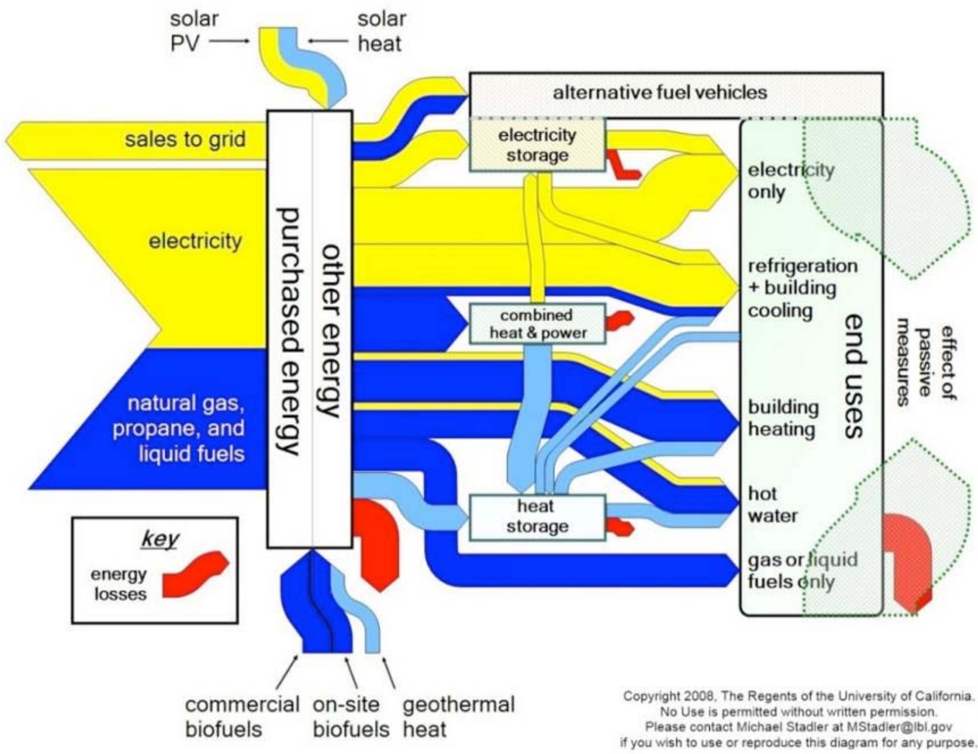

Figure 3-1: Schematic of energy flows in DER-CAM

Available energy inputs to the site are solar radiation, utility electricity, and utility natural gas[4]. The location-specific solar radiation will impact the adoption of PV and solar thermal technologies. Previous work has shown that the utility electricity prices and utility natural gas prices are main drivers for natural gas fired distributed technologies. The gross margin of a gas-fired DER system from selling a unit of electricity (spark spread) determines the attractiveness of the system. In case of TOU tariffs, the spark spread increases dramatically during the expensive (normally noon) hours, which increases the attractiveness of gas-fired technologies.

Investment & Planning DER-CAM, which is used in this work, solves the mixed integer linear problem over a given time horizon, e.g., a year, and selects the economically or environmental optimal combination of utility electricity purchase, on-site generation, storage and cooling equipment required to meet the site's end-use loads at each time step. In other words, DER-CAM looks into the optimal combination/adoption and operation of technologies to supply the services specified on the right hand side of Figure 3-1 from a customer's point of view. All the different arrows in Figure 3-1 represent energy flows, and DER-CAM optimizes these energy

[4] It could be also biogas, but in this work only natural gas is used.

flows to minimize costs and/or CO_2 emissions. Blue arrows represent natural gas or any bio-fuel, yellow represents electricity, and light blue heat and waste heat, which can be stored and/or used to supply the heat loads or cooling loads via absorption cooling.

The outputs of DER-CAM include the optimal DG/storage adoption and an hourly operating schedule, as well as the resulting costs, fuel consumption, and CO_2 emissions. All available technologies compete and collaborate, and simultaneous results are derived. In this way, it can be shown that PV and stationary electric storage can compete in certain situations. If the focus of the optimization is on cost minimization and a TOU rate with high costs during noon hours is used, then it can be demonstrated that stationary electric storage will be discharged at the same time when the PV system is operational (Stadler et al., 2009). The on-site fuel use and carbon savings are, therefore, quite accurately estimated and can deviate significantly from simple estimates. Also, the optimal pattern of utility electricity purchase is accurately delivered. Finding likely solutions to this complex problem for multiple buildings would be impossible using simple analysis, e.g. using assumed equipment operating schedules and capacity factors. Because CEUS buildings each represent a certain segment of the commercial building sector, results from typical buildings can readily be scaled up to the state level in order to provide policymaking insights.

4 Data sources

4.1 CEUS

The starting point for the load profiles used within DER-CAM is the California Commercial End-Use Survey (CEUS) database which contains 2790 premises in total. Not all utilities participated in CEUS, the most notable absence being the Los Angeles Department of Water and Power (LADWP) and FZ14+15. For this study, the small zones FZ2 and 6 were also excluded, and the researchers also eliminated the miscellaneous building types for which there is insufficient information for simulation. The remaining solid red slices of the pie represent 68% of the total commercial electric demand. Because the focus here is on mid-sized buildings above 100 kW (or 50 kW in the case of restaurants), almost half of the red slices were also eliminated, leaving 37% of the total commercial electric demand in the service territories of Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego and Gas Electric (SDG&E) (CEUS, 2006).

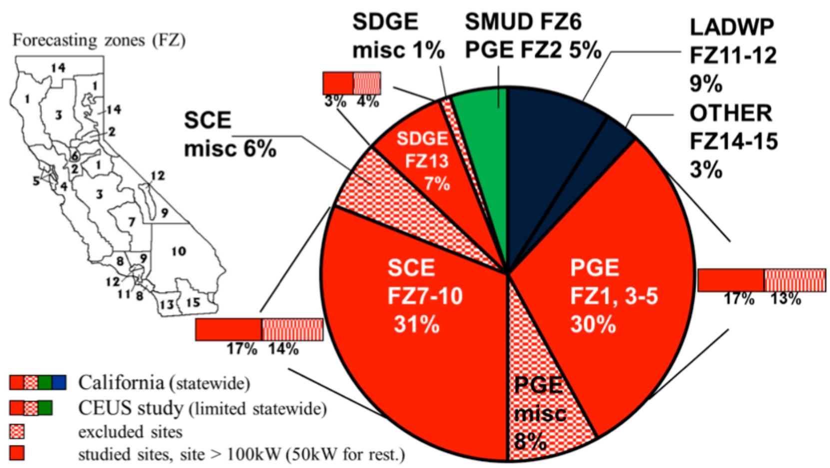

Figure 4-1: Commercial electric demand fractions

147 representative CA sites in different climate zones with an electric peak load of at least 100 kW (50 kW for restaurant buildings), were picked (see Table 4-2). The reason for selecting a smaller cut-off boundary for restaurants is that the restaurant sector consumes roughly 25% of the natural gas, accounted for in CEUS, and this can make it a prime candidate for CHP (CEUS, 2006).

Every building with an electric peak load above 100 kW, respectively 50 kW for restaurant buildings, (green cells from Figure 4-1) is optimized with DER-CAM and the results are inflated to the state level by using the sample frame numbers from Table 4-2.

Table 4-1: Electric peak loads for various building types and climate zones (green cells are represented in this study), FZ: forecasting climate zone

		Peak electric load (kW)								
Category	Size	FZ 01	FZ 03	FZ 04	FZ 05	FZ 07	FZ 08	FZ 09	FZ 10	FZ 13
Hotel / Motel	S	5.8	39.5	14.0	12.9	9.9	16.9	21.4	29.9	20.5
	M	46.4	278.9	118.1	138.2	87.4	143.9	215.4	252.4	191.8
	L	503.0	1535.4	578.8	835.5	461.2	847.7	1122.4	1387.9	1052.7
Small Office	S	1.4	1.3	5.9	0.7	1.2	1.0	1.3	1.4	0.9
	M	9.8	10.2	41.6	4.9	7.4	7.1	8.1	8.5	5.9
	L	56.9	63.7	242.3	33.0	43.4	48.6	53.8	53.8	37.8
Unref. Warehouse	S	-	0.9	4.0	1.7	-	2.8	5.7	6.1	2.5
	M	-	11.9	44.4	20.0	-	30.2	66.7	68.4	28.5
	L	-	120.2	333.9	198.9	-	331.0	568.4	588.1	235.0
School	S	21.8	18.0	28.0	23.7	23.8	23.5	25.8	25.3	17.2
	M	163.9	128.6	153.8	152.3	148.8	139.9	164.7	186.4	143.0
	L	641.2	614.7	556.6	550.4	597.8	518.7	652.6	760.7	515.8
Retail Store	S	4.1	7.2	5.6	4.3	7.3	5.1	3.9	5.5	4.7
	M	56.3	89.7	63.4	52.8	76.8	56.9	47.9	59.1	53.5
	L	547.1	740.3	494.0	475.7	678.3	501.1	386.4	549.0	505.3
Restaurant	S	8.1	7.4	10.2	8.0	9.1	9.4	9.0	8.0	7.5
	M	33.2	30.2	37.0	31.4	35.1	31.8	32.0	27.2	28.6
	L	76.5	84.5	111.2	93.6	95.1	96.6	92.8	77.9	94.3
Ref. Warehouse	S	56.3	58.6	41.4	47.2	10.5	25.2	73.8	54.1	16.2
	M	973.6	556.5	408.6	462.1	137.1	366.3	953.7	780.3	217.7
	L	-	2484.5	2238.3	2618.6	1030.0	1501.1	4233.1	3066.0	973.2
Large Office	S	128.0	423.3	264.3	372.6	102.0	299.8	1307.4	250.7	376.4
	M	354.8	981.4	665.8	912.7	288.0	731.4	3450.7	639.1	962.8
	L	-	2542.4	1640.3	2359.9	608.5	1708.5	8715.0	1369.6	2516.7
Health Care	S	28.0	14.2	18.2	22.7	31.0	33.7	31.7	31.3	24.5
	M	335.3	170.2	203.1	0.3	403.8	391.5	311.0	371.7	399.3
	L	2027.7	1174.4	1333.1	1891.9	2447.2	2250.8	2251.3	2345.7	2197.3
Food / Liquor	S	8.4	8.8	9.2	8.2	11.7	8.9	9.1	9.7	11.0
	M	67.7	52.5	63.5	64.4	77.8	59.5	70.5	66.0	87.0
	L	291.2	285.2	307.6	291.2	399.0	323.7	352.0	318.1	371.9
College	S	8.1	22.4	15.3	26.5	8.5	19.0	21.6	12.4	33.1
	M	301.5	362.3	480.9	654.4	206.3	505.3	543.2	275.2	730.7
	L	2030.4	2529.5	2420.1	3146.8	762.8	2945.2	3204.6	1937.3	4663.2

Source: CEUS and LBNL calculations

Table 4-2: CEUS sample frame numbers for every building type and forecasting climate zone (FZ)

		Sample frame numbers								
Category	**Size**	**FZ 1**	**FZ 3**	**FZ 4**	**FZ 5**	**FZ 7**	**FZ 8**	**FZ 9**	FZ 10	FZ 13
Hotel/Motel	**S**	531	459	922	879	223	642	623	541	649
	M	36	94	179	203	30	234	126	151	170
	L	2	3	17	55	2	60	20	28	40
Small Office	**S**	3,581	10,506	10,945	15,552	2,178	18,844	14,863	9,182	22,042
	M	1,604	5,386	7,109	9,104	1,515	12,437	9,285	6,947	14,127
	L	223	1,084	1,785	2,780	273	4,139	2,259	1,516	3,135
Unref. Warehouse	**S**	892	3,653	2,818	5,188	538	5,878	5,347	2,437	4,092
	M	46	416	636	1,071	61	1,167	1,185	515	575
	L	4	39	60	101	1	116	113	71	46
School	**S**	487	1,194	1,215	1,594	327	1,158	1,102	536	899
	M	69	444	400	354	104	466	561	456	392
	L	6	65	70	54	17	107	115	83	116
Retail Store	**S**	2,159	5,246	7,308	10,917	1,579	13,337	10,283	6,596	8,866
	M	205	974	1,498	2,084	315	3,134	2,031	1,598	1,709
	L	13	110	187	235	35	406	318	246	197
Restaurant	**S**	1,019	2,202	3,572	7,030	568	5,153	3,900	1,987	4,123
	M	278	1,051	1,683	2,026	281	3,153	2,346	1,499	1,822
	L	32	348	362	450	89	846	626	458	421
Ref. Warehouse	**S**	48	187	137	211	37	186	161	61	282
	M	6	89	39	29	7	22	14	10	12
	L	0	14	12	4	3	7	7	6	4
Large Office	**S**	9	95	302	585	15	713	304	147	331
	M	3	16	139	252	8	266	94	34	109
	L	0	6	55	114	3	107	26	3	51
Health Care	**S**	201	596	655	1,041	145	774	763	489	865
	M	22	100	100	144	32	153	136	96	128
	L	4	17	31	45	6	32	25	13	19
Food/Liquor	**S**	574	2,049	2,350	4,148	428	3,059	3,390	1,471	1,963
	M	129	581	521	599	145	631	572	357	554
	L	36	102	173	191	27	289	224	159	115
College	**S**	67	164	284	392	89	659	661	288	456
	M	6	19	24	55	6	59	36	24	40
	L	1	6	13	12	1	17	13	7	13

Source: CEUS and LBNL calculations

For more information on CEUS please refer to chapter 12.5.1 in the appendix. A detailed discussion of the restaurant load profiles can be found in chapter 12.5.2.

4.2 Electric tariffs and natural gas prices

The electric rates as well as natural gas prices are important drivers for CHP adoption and are analyzed in detail in chapter 12.6 of the appendix. The electric and natural gas rates that are used are summarized in chapter 14.7 of the appendix. Please note that the tariffs are kept constant in real terms, and therefore, the numbers shown in chapter 14.7 also apply to the 2020 runs.

In the case of natural gas, the current low prices seem to be unrealistic estimates for 2020 and 2030, and therefore, different price assumptions were tested within this project. For example run set (1), was using low natural gas prices for the optimization (see table Table 4-3 or Table 14-7 from the appendix) and run set (2) was using the higher natural gas prices for the optimization runs (see Table 4-4 or Table 14-8 from the appendix). Please note that in this study only natural gas is used as input fuel for internal combustion engines, micro-turbines, and fuel cells; no biogas is considered.

A run set is defined as 147 individual optimization runs for the selected buildings using the same optimization settings and parameters.

Table 4-3: Basic fuel prices ($/kWh$_t$) in 2012US$ for run set (1)

utility	season	natural gas price ($/kWh$_t$)
PG&E	Winter	0.02032
	Summer	0.01864
SCE	Winter	0.01678
	Summer	0.01678
SDG&E	Winter	0.01780
	Summer	0.01780

(based on PG&E, SCE, SDG&E tariff information)

Table 4-4: Higher fuel prices ($/kWh$_t$) in 2012US$ for run set (2) and all other subsequent run sets

utility	Season	natural gas price ($/kWh$_t$)
PG&E	Winter	0.026059
	Summer	0.023668
SCE	Winter	0.027944
	Summer	0.027944
SDG&E	Winter	0.021135
	Summer	0.021135

(based on PG&E, SCE, SDG&E tariff information)

The final run set (4) uses electric tariffs based on transmission levels/high distribution levels for customers above 1000 kW peak demand (see also chapter 14.7 from the appendix).

For more information on tariffs, please see the appendix.

4.3 Marginal CO_2 emissions from the utility

A major goal of CHP adoption is to reduce the CO_2 emissions from burning fossil fuel by increasing the total system efficiency. However, since the benchmark for electricity purchases are the CO_2 emissions of the marginal power plant within a specific utility service territory, the emissions for 2020 and 2030 need to be estimated. Based on Mahone et al., 2008 and E[3], 2009, the available hourly 2020 marginal CO_2 emissions are assumed with an average of about 510 gCO_2/kWh_e. With McCollum et al. (2011) the hourly CO_2 emissions for 2030 can be estimated. The calculated 2030 average CO_2 emissions are about 40% below the E[3] 2009 estimates from Mahone et al., 2008 and E[3], 2009.

As the results show, the de-carbonization of the electricity generation has a strong impact on CHP adoption. A detailed analysis of the expected marginal CO_2 emissions can be found in chapter 14.6 Projected CO_2 emissions. Run set (3) was used as calibration run set to estimate the impact of the two different CO_2 levels on technology adoption.

4.4 NOx emissions and treatment costs

Nitrogen oxides (NOx) are emissions from power plants and natural gas fired DG which can compromise human health. Therefore, in 2003 the "Clear Skies in California" program was initiated to reduce the impact on citizens in California. In 2005 this legislation became part of the U.S. Senate Environment and Public Works (EPA, 2003; Senate, 2013).

Figure 4-2 shows that Southern California has the highest NOx emission levels. The following counties had a daily 1-hour maximum NOx concentration above 80 ppm: Imperial Co, Los Angeles Co, and San Bernardino Co. Within that study it is assumed that in 2020 respectively in 2030 the limitation of NOx emission will be about 50 ppm (EPA, 2009b, p. ES-1) for the overall State California.

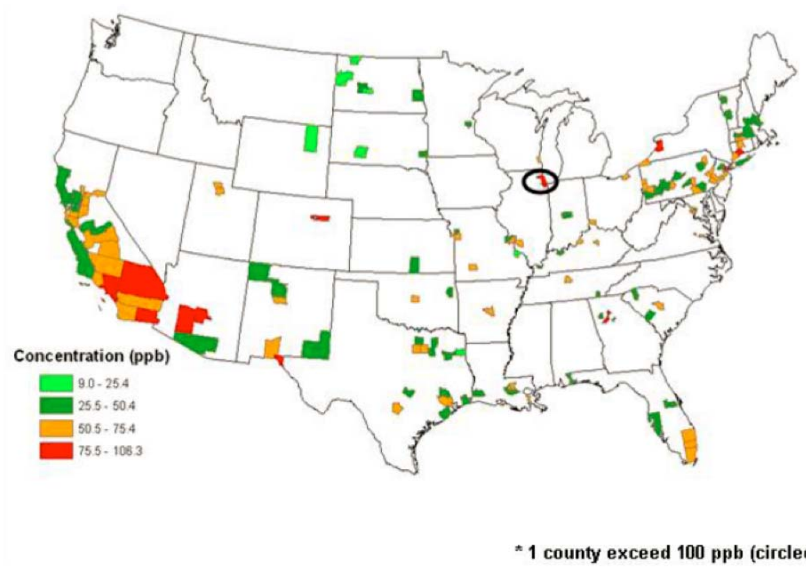

Figure 4-2: 2005-2007 3-year averaged design values (ppb) for 99th percentile daily 1-hour maximum NO_2 concentrations (source: EPA, 2009b, p. 3-3)

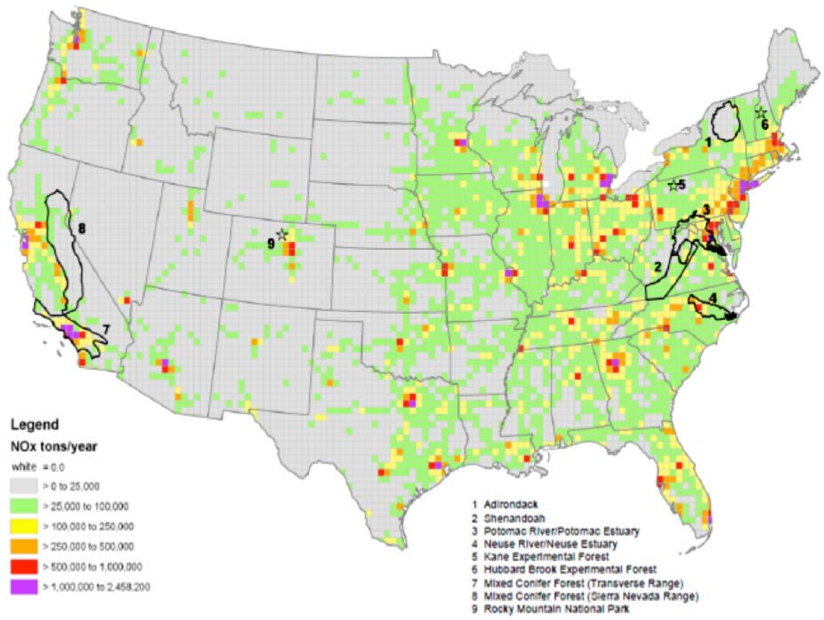

Figure 4-3: Spatial distribution of annual total NOx emissions (tons/yr) for 2002 (source: EPA, 2011, p. 2-9)

Industrial, commercial, and residential combustion is responsible for about 12% of the overall NOx emissions (see Figure 4-4) (EPA, 2009a).

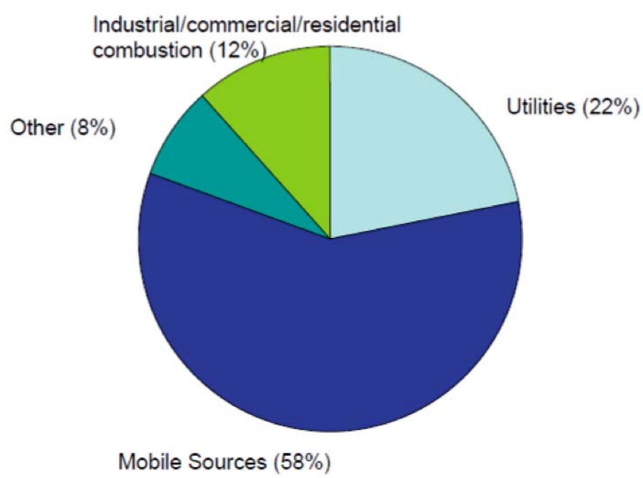

Figure 4-4: Sources of NOx Pollution (source: EPA, 2009a)

Table 4-5: Specific NOx emissions for 2009 technologies based on EPA, 2008 (left part of table) and EERE, 2002) (right part of table) without emission control

type	GT	MT	ICE (rich burn)	FC	GT	MT	ICE	FC	grid
size in kW_e	1000	65	na	100	na	na	na	na	na
NOx, lb/MWh_e	2.43	0.22	0.10	0.05	1.20	0.49	5.90	0.02	3.50
NOx, kg/MWh_e	1.10	0.10	0.05	0.02	0.54	0.22	2.68	0.01	1.59

As Table 4-5 shows most technologies will require emission control or an after treatment system to comply with the 0.07 lb/MWh emission standards in California (CARB, 2006). Thus, the final run set (4) was created by the introduction of NOx treatment costs of 300 $/kW (ICF, 2012) for internal combustion engines (ICE systems), which are selected frequently as optimal technology (see chapter 5).

4.5 Technology costs

A summary of selected cost and performance data for 2020 and 2030 is given in the following tables (Table 4-6 and Table 4-7) and more information can be found in chapter 12.8 of the appendix. Most striking is that the Annual Energy Outlook for 2009-2011 is more conservative about the fuel cell cost reductions as the Annual Energy Outlook 2004 (see different 2020 columns in Table 4-6).

Please note that the interest rate for investments was set to 3% and the maximum payback period for investments was set to 5 years (except otherwise specified in a sensitivity run set, see chapter 5).

Table 4-6: Menu of available DG and CHP equipment options in 2020 and 2030, (source: AEO, 2009; AEO, 2010; AEO, 2011; CPUC, 2011; Firestone, 2004; Goldstein et al., 2003; SGIP, 2008; own calculations)

	capacity (kW)	installed costs ($US\$_{2008}$/kW)			installed costs with heat recovery ($US\$_{2008}$/kW)			variable maintenance ($US\$_{2008}$/kWh)	electric efficiency (%), (HHV)			lifetime (a)
year / source		2020*)	2020**)	2030**)	2020*)	2020**)	2030**)	2020/2030	2020*)	2020**)	2030**)	
ICE-small	60	3101	2098	1587				0.02	0.29	0.29	0.29	20
ICE-med	250	1690	1143	865				0.01	0.30	0.30	0.30	20
GT	1000	2147	2039	1932				0.01	0.22	0.22	0.22	20
MT-small	60	2412	2116	1410				0.02	0.25	0.28	0.31	10
MT-med	150	1964	1723	1148				0.02	0.26	0.29	0.33	10
FC-small	100	2715	4969	3605				0.03	0.36	0.40	0.46	10
FC-med	250	2176	3981	2889				0.03	0.36	0.40	0.46	10
ICE-HX-small	60				4080	2760	2088	0.02	0.29	0.29	0.29	20
ICE-HX-med	250				2485	1681	1271	0.01	0.30	0.30	0.30	20
GT-HX	1000				2941	2794	2647	0.01	0.22	0.22	0.22	20
MT-HX-small	60				2710	2377	1584	0.02	0.25	0.28	0.31	10
MT-HX-med	150				2207	1935	1290	0.02	0.26	0.29	0.33	10
FC-HX-small	100				3157	5778	4192	0.03	0.36	0.40	0.46	10
FC-HX-med	250				2530	4629	3359	0.03	0.36	0.40	0.46	10

abbreviations: ICE: natural gas fired internal combustion engine; GT: gas turbine; MT: micro turbine; FC: fuel cell; HX: heat exchanger for waste heat utilization.

*) projections based on estimates Annual Energy Outlook 2004

**) projections based on estimates Annual Energy Outlook 2009-2011

Table 4-7: Turnkey costs and lifetime for energy storage, chiller, PV and solar thermal equipment options (source: Firestone, 2004; Goldstein et al., 2003; own calculations)

parameter	variable costs (US$/kWh[5] or US$/kW)	lifetime (years)
electric Storage	193	5
heat Storage	100	17
abs Chiller	685	20
Photovoltaic (PV)	3,237 US$/kW and 1,500 US$/kW for run set (4c5, 4e9, 4e11, and 4e12)	30
solar thermal	500	15

Table 4-8: Energy storage parameter, (source: Firestone, 2004; Goldstein et al., 2003; own calculations)

parameter	electrical	thermal	description
charging efficiency	0.90	0.90	portion of energy input to storage that is useful
discharging efficiency	0.90	0.90	portion of energy output from storage that is useful
self-discharging	0.001	0.01	portion of state of charge lost per hour
maximum charge rate	0.10	0.25	maximum portion of rated capacity that can be added to storage in an hour
maximum discharge rate	0.25	0.25	maximum portion of rated capacity that can be withdrawn from storage in an hour
minimum state of charge	0.30	0.00	minimum state of charge as apportion of the rated capacity

4.6 Assumptions for SGIP and feed-in tariffs

All assumptions for the SGIP and feed-in tariffs can be found in chapter 13.6 and 13.7 of the appendix. All those regulatory constraints were implemented/programmed in DER-CAM during this project and have been considered in the optimization runs.

[5] US$/kWh for storage technologies.

5 Optimization runs

5.1 Overview assumptions

As already indicated in the previous chapter a great number of calibration runs was performed and run sets (1) to (3) were just executed for these calibration reasons. Thus, the final runs start with run set (4) numbering. The results for the calibration run sets (1) – (3) can be found in chapter 14.8 of the appendix.[6]

All runs in run set (4) assume:

- use of NOx treatment costs for ICE systems (ICF, 2012)
- tariffs and prices based on chapter 14.7 of the appendix with
    - realistic higher natural gas prices (Table 14-8 from Basic Results of DER-CAM Optimization Memo)
    - realistic low electricity prices for customers above 1000 kW_e peak demand (Table 14-9 and Table 14-10 from Basic Results of DER-CAM Simulation Memo).

Table 5-1 summarizes the different settings for the performed runs within run set (4). Please note that two strategies are used to simulate the adoption of DER technologies in the commercial sector:

- cost minimization and
- *onsite* CO_2 minimization.

In the cost minimization it is assumed that the decision makers focus only on energy cost minimization and there is no focus on the environment. The derived CO_2 emissions in these cases can be therefore higher than in the base cases without any investments in DER. The other extreme is that the decision makers focus only on the environment and *onsite* CO_2 reduction. This however also means that costs can increase a lot if there is no focus on energy costs. Thus, for the *onsite* CO_2 minimization cases in this work, the authors assumed a cost cap that ensures that the energy costs (including investment costs) after investments in DER cannot be higher than in the base case without any DER investments. There is only one exemption to this cost constraint: zero net energy buildings (ZNEB) runs allow higher costs as in the base case otherwise ZNEB would not be a viable solution in many cases[7].

Furthermore, please note that sold electricity (from PV or CHP) does not change the onsite CO_2 emissions since the energy is consumed offsite. On the other hand, electricity purchased from the utility accounts for the *onsite* CO_2 emissions.

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[6] Please note that an accounting problem in Excel resulted in wrong stationary storage numbers in appendix 14, which were corrected in appendix 15.9.

[7] The cost cap for ZNEB was set to 400% of base case costs.

Table 5 1: Descriptions of the underlying details for available optimization runs within run set (4)

run set	description	2020	2030
(4a1)	base case for the run set (4) without any DER units (all energy needs to be purchased from the utility); marginal CO_2 emissions for 2020 are considered based on Table 14-1 of the appendix	X	
(4a2)	base case for the run set (4) without any DER units (all energy needs to be purchased from the utility); 40% reduced marginal CO_2 emissions for 2030 are considered based on Table 14-2 of the appendix		X
(4a3)	base case for sensitivity run set (4e8) without any DER units (all energy needs to be purchased from the utility); marginal CO_2 emissions for 2030 are considered with 2020 values to estimate the impact of less grid de-carbonization on CHP adoption in 2030		X
(4b1)	cost minimization strategy	X	
(4b2)	cost minimization strategy combined with SGIP	X	
(4b3)	cost minimization strategy, SGIP, and higher electrical FC efficiency of 46% compared to numbers in Table 4-6)	X	
(4b4)	cost minimization strategy, SGIP, higher electrical FC efficiency, and a maximum payback period of 10 years instead of 5 years	X	
(4c1)	cost minimization strategy		X
(4c2)	cost minimization strategy with enabled feed-in tariff for DG and PV		X
(4c3)	cost minimization strategy and ZNEB constraint forcing the buildings to be balanced on energy purchase and sales; the ZNEB constraint is based on natural gas equivalents; ZNEB runs require feed-in tariffs (FiT) to be turned on within DER-CAM to allow sales and the fulfillment of the ZNEB constraint; CHP and PV sales are allowed		X
(4c4)	equal to run set (4c1) except higher overall efficiency for fuel cells (60% electric efficiency instead of 46%) and higher lifetime of 20 years for fuel cells instead of 10 years is considered		X
(4c5)	equal to run set (4c1) except that higher lifetime of 20 years for fuel cells instead of 10 years is considered. Also, lower PV costs of $1500/kW instead of $3227kW are considered		X
(4c6)	cost minimization, 20 year lifetime for fuel cells, higher electrical FC efficiency of 60%, but 10 payback period for investments		X
(4d1)	carbon minimization strategy for 2020, marginal CO_2 emissions for 2020 are considered based on Table 14-1 of the appendix	X	
(4d2)	carbon minimization strategy with SGIP, marginal CO_2 emissions for 2020 are considered based on Table 14-1 of the appendix	X	

(4d3)	carbon minimization strategy with SGIP, and higher electrical FC efficiency of 46% compared to numbers in Table 4-6, marginal CO_2 emissions for 2020 are considered based on Table 14-1 of the appendix	X	
(4d4)	carbon minimization strategy with SGIP, higher electrical FC efficiency of 46% compared to numbers in Table 4-6, and a maximum payback period of 10 years	X	
(4e1)	carbon minimization strategy for 2030		X
(4e2)	carbon minimization strategy with enabled feed-in tariffs for DG and PV sales		X
(4e3)	carbon minimizing strategy and increased lifetime of fuel cells (from 10 to 20 years); a fuel cell constraint is applied that forces fuel cells to run 24 hours a day (if attractive) with minimal variability; this behavior is similar to a SOFC, 40% reduced marginal CO_2 emissions for 2030 are considered based on Table 14-2 of the appendix		X
(4e4)	equal to run set (4e3) except that fuel cells have no runtime restrictions and can follow the load; this behavior is very similar to a PEMFC, 40% reduced marginal CO_2 emissions for 2030 are considered based on Table 14-2 of the appendix		X
(4e5)	equal to run set (4e3) plus the ZNEB constraint (which enables CHP and PV sales), 40% reduced marginal CO_2 emissions for 2030 are considered based on Table 14-2 of the appendix		X
(4e6)	equal to run set (4e5) except that fuel cells have no runtime restrictions, 40% reduced marginal CO_2 emissions for 2030 are considered based on Table 14-2 of the appendix		X
(4e7)	equal to run set (4e3) except that an overall efficiency of 92% (60% electric efficiency) for fuel cells is considered		X
(4e8)	equal to run set (4e7) expect that the marginal carbon emissions is considered to be equal to the 2020 values, based on Table 14-1 of the appendix		X
(4e9)	equal to run set (4e3) expect that lower PV costs of $1500/kW instead of $3227/kW are considered		X
(4e10)	equal to run set (4e7) expect that a maximum payback period of 10 instead of the standard 5 years is assumed		X
(4e11)	equal to run set (4e10) expect that lower PV costs of $1500/kW instead of $3227/kW are considered; PV and DG sales are enabled		X
(4e12)	equal to run set (4e11) plus the ZNEB constraint; DG and PV sales are enabled		X
(4e13)	equal to run set (4e10) expect that the smallest FC technology was changed from 100 to 60 kW which is the smallest DG technology size for ICE, GT and MT; technology costs remain unchanged		X
(4e14)	equal to run set (4e13) expect that the smallest size for DG technologies (ICE, GT, MT, and FC) has been changed from 60 to 25 kW		X

Please note that some of the optimization results are already shown in the memorandums in the appendix, and due to updates in the run sets, slight deviations between the results in the appendix and the next chapter might be observed.

5.2 Overview optimization results

This chapter should give the reader a high-level overview about the CHP results, so that she/he can skip the next chapter "Detailed optimization results" if wanted.

Runs (4a) are the base case runs, where no CHP / CCHP nor any other DER is allowed and all energy needs to be purchased from the local utility. All other runs are compared to them.

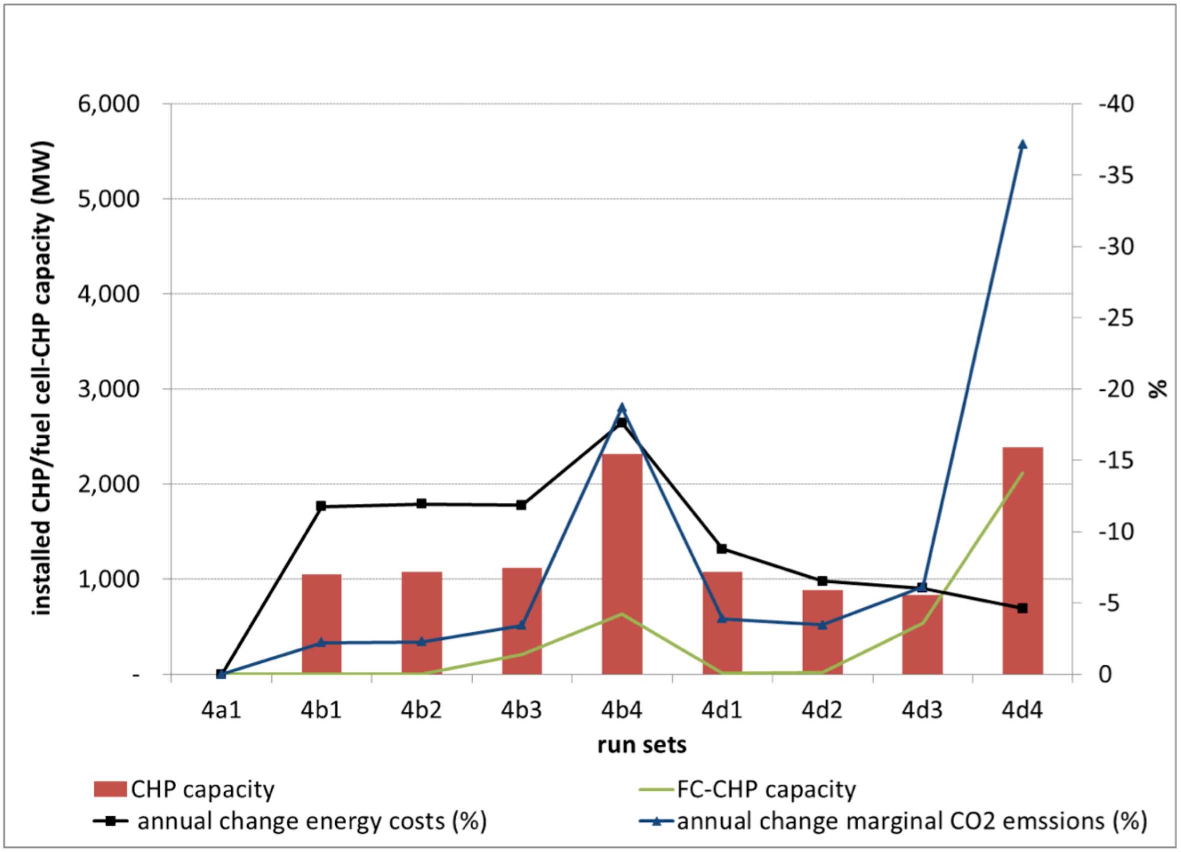

Figure 5-1: High-level CHP results for 2020 (source: DER-CAM runs)

Figure 5-1 shows the CHP, CHP-enabled fuel cell adoption as well as the corresponding annual CO_2 and cost savings compared to the base case run (4a1). Run set (4d4) shows the highest CHP as well as CHP-enabled fuel cell adoption in combination with the highest CO_2 savings in 2020. Since this run set also shows energy cost savings it is referred to as "optimistic case" throughout this work.

Figure 5-2 shows the same results for all 2030 run sets. From this figure it becomes evident that only CO_2 minimization strategies (run sets 4e) of building owners can elevate the CHP-enabled fuel cell adoption (green line in Figure 5-2). Run set (4e10) shows considerable amount of CHP, CHP-enabled fuel cells in combination with cost and CO_2 reductions. Thus run set (4e10) is frequently used in the sub-sequent chapters. Run set (4e12), the ZNEB run set is interesting since it demonstrates that ZNEB can support the CHP-enabled fuel cell adoption. However, run sets (4e5) and (4e6), also ZNEB runs show not CHP enabled fuel cell adoption, demonstrating how sensitive the results are to investment costs, efficiencies, and payback periods.

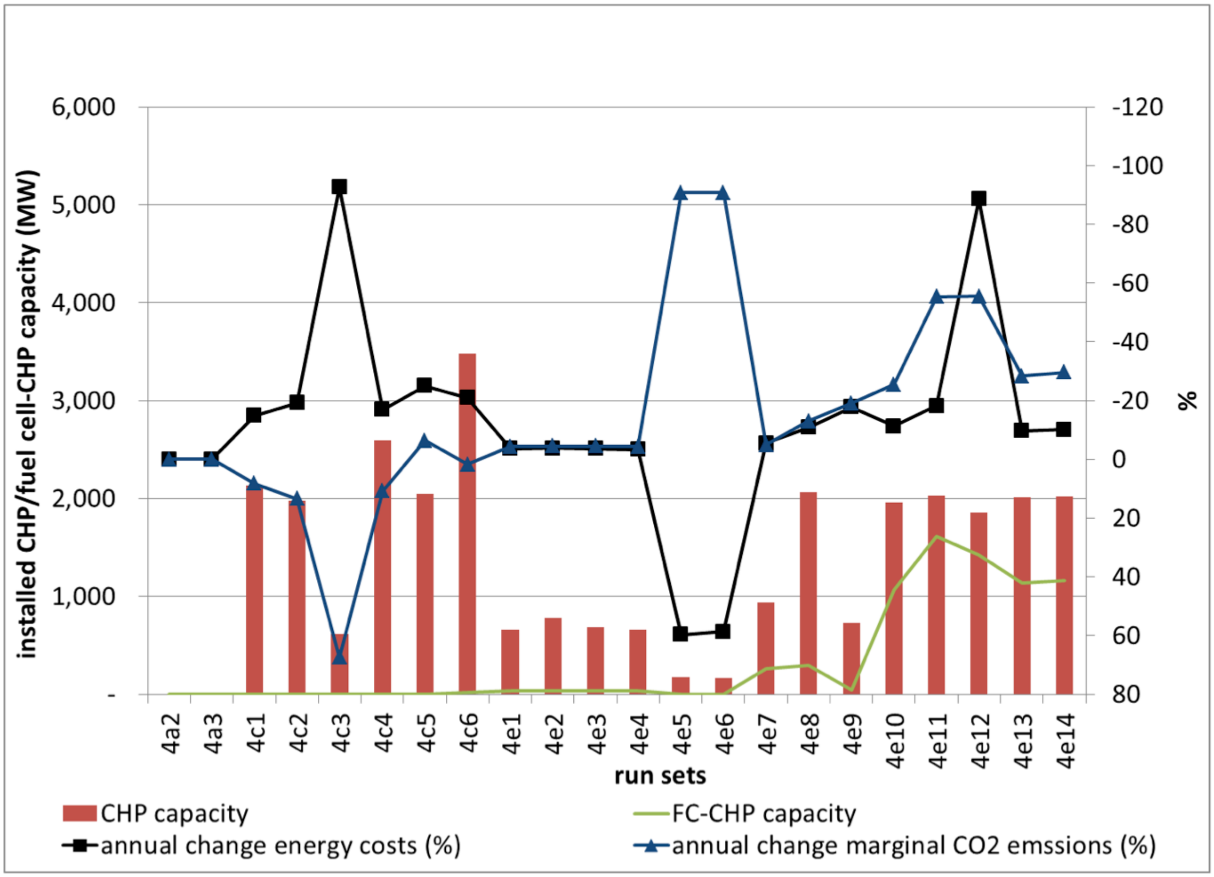

Figure 5-2: High-level CHP results for 2030 (source: DER-CAM runs)

5.3 Detailed optimization results

Chapter 5.3 describes the results of the major run sets 4 in more detail, and therefore, readers who are neither interested in the details of other DER technologies nor in their interaction can skip this chapter and directly continue with chapter 5.4.

5.3.1 Results for 2020

While run set (4b1) is a pure cost minimization case for 2020, run set (4b2) considers cost minimization combined with a SGIP. Both cases show very similar CHP adoption since the SGIP program seems not to be helpful due to the low system efficiencies for fuel cells. Thus, run set (4b3) was performed, which uses higher electric efficiencies of 46% for fuel cells (FCs) in 2020. This run set also does not show any significant increase in total DG adoption. Because of the SGIP 212 MW of fuel cells are adopted, but it also reduces the internal combustion engine (ICE) as well as micro-turbine (MT) adoption (see table below). These runs result in the conclusion that a 5 year payback period for investments for 2020 might be too tight and run set (4b4) proves this by showing a 50% increase in DG adoption from approx. 1800 to 2800 MW (see Table 5-1).

The SGIP does not result in any significant reduction of CO_2 emissions except in the case (4b4) with an assumed 10 year payback period for investments. However, this 10 year payback period also results in 10 times more PV adoption compared to the previous runs and this contributes greatly to the CO_2 reduction.

Table 5-1: 2020 result summary of run sets (4b) and (4d) (source: DER-CAM runs)

runs for 2020 :	4a1	4b1	4b2	4b3	4b4	4d1	4d2	4d3	4d4
run description	base case	2020 (min US$)	2020 (min US$) + SGIP	2020 (min US$) + high FC efficiency + SGIP	2020 (min US$) + high FC efficiency + 10yrs payback + SGIP	2020 (min CO_2)	2020 (min CO_2) + SGIP	2020 (min CO_2) + high FC efficiency + SGIP	2020 (min CO_2) + high FC efficiency + 10yrs payback + SGIP
available profiles	147	147	147	147	147	147	147	147	147
annual energy costs (bln $)	5.3	4.7	4.7	4.7	4.4	4.9	5.0	5.0	5.1
annual energy costs (%)	100.0	88.2	88.1	88.2	82.4	91.2	93.5	94.0	95.4
change in annual energy costs (%)		(11.8)	(11.9)	(11.8)	(17.6)	(8.8)	(6.5)	(6.0)	(4.6)
annual marginal CO_2 emissions (Mt/a)	21.8	21.3	21.3	21.0	17.7	20.9	21.0	20.5	13.7
annual marginal CO_2 emissions (%)	100.0	97.8	97.7	96.6	81.3	96.1	96.5	93.9	62.8
change in annual marginal CO_2 emssions (%)		(2.2)	(2.3)	(3.4)	(18.7)	(3.9)	(3.5)	(6.1)	(37.2)
installed DG capacities (MW)		1,764.7	1,795.8	1,798.0	2,801.7	1,124.0	885.2	878.2	2,540.2
installed DG capacities (GW)		1.8	1.8	1.8	2.8	1.1	0.9	0.9	2.5
installed PV capacities (MW)		279.7	309.1	221.2	2,228.3	290.1	137.0	97.9	4,064.9
installed PV capacities (GW)		0.3	0.3	0.2	2.2	0.3	0.1	0.1	4.1
installed Solar Thermal capacities (MW)		56.7	8.8	8.8	73.0	174.8	504.5	148.8	791.4
installed Solar Thermal capacities (GW)		0.1	0.0	0.0	0.1	0.2	0.5	0.1	0.8
electricity produced by DG (without PV) (GWh)		10,040.5	10,220.7	10,458.1	14,834.6	6,880.9	5,365.2	6,048.5	17,456.9
PV and DG sales (GWh)		-	-	-	-	-	-	-	-
PV sales (GWh)		-	-	-	-	-	-	-	-
cooling offset (GWh)		696.2	686.6	658.3	1,047.0	664.8	667.4	335.9	913.3
building linked mobile electric storage (GWh)		-	-	-	-	-	-	-	-
electric stationary storage (GWh)		0.7	0.1	0.2	0.1	0.8	0.1	0.7	11.6
heat storage (GWh)		-	-	-	-	-	-	0.1	4.1
DG capacity factor (%)		65.0	65.0	66.4	60.4	69.9	69.2	78.6	78.4

Table 5-2: 2020 result summary of run sets (4b) and (4d) (installed DG capacity, MW) (source: DER-CAM runs)

run	4a1	4b1	4b2	4b3	4b4	4d1	4d2	4d3	4d4
installed DG capacity (MW)	base case	2020 (min US$)	2020 (min US$) + SGIP	2020 (min US$) + high FC efficiency + SGIP	2020 (min US$) + high FC efficiency + 10yrs payback + SGIP	2020 (min CO2)	2020 (min CO2) + SGIP	2020 (min CO2) + high FC efficiency + SGIP	2020 (min CO2) + high FC efficiency + 10yrs payback + SGIP
total installed DG capacity (MW)	-	1,764.7	1,795.8	1,798.0	2,801.7	1,124.0	885.2	878.2	2,540.2
ICE	-	716.5	717.7	678.1	484.6	45.8	-	43.3	55.9
ICE-HX	-	907.4	932.7	790.0	1,684.8	801.0	695.3	154.8	0.8
GT	-	-	-	-	-	-	-	-	-
GT-HX	-	-	-	-	-	-	-	-	-
MT	-	-	6.0	-	-	-	-	-	-
MT-HX	-	140.8	139.4	118.1	-	269.3	168.7	145.5	268.1
FC	-	-	-	-	-	-	-	-	99.7
FC-HX	-	-	-	211.8	632.3	8.0	21.3	534.7	2,115.8
% ICE of DG	-	92.0	91.9	81.7	77.4	75.3	78.5	22.5	2.2
% GT of DG	-	-	-	-	-	-	-	-	-
% MT of DG	-	8.0	8.1	6.6	-	24.0	19.1	16.6	10.6
% FC of DG	-	-	-	11.8	22.6	0.7	2.4	60.9	87.2

While run set (4d1) is a pure carbon minimization case for 2020, run set (4d2) is a carbon minimization case combined with a SGIP. While the installed DG capacity is about 1124 MW in run (4d1) only 885 MW are installed in run (4d2) with SGIP used. The applied SGIP increases the fuel cell capacity from 8 MW in run set (4d1) to 21.3 MW in run set (4d2), but also reduces the adopted MTs as well as ICEs with heat exchanger (HX) (see Table 5-2). Run set (4d3) is an extension of run (4d2) where the average electrical efficiency of fuel cells is increased from 40% to 46%. While the installed DG capacity is quite constant with about 880 MW the installed FC-HX capacity increases from 21.3 to 534.7 MW. The average DG capacity factor increases from 69.2 to 78.6%. Finally, run set (4d4) is an extension of run (4d3) where the maximal payback period was changed from 5 to 10 years. This changes greatly the CHP and PV adoption. About 2540 MW installed DG capacity and about 4065 MW PV capacity are utilized with an average DG/CHP capacity factor of 78.4%. A reduction of carbon emissions of 37.2% compared to the base case is feasible. 2116 MW out of the 2540 MW are fuel cells with waste heat utilization.

Run set (4d4) shows the most CHP adoption in the commercial sector buildings of 2385 MW (ICE-HX, MT-HX, FC-HX), reduces the CO_2 emissions by 37.2%, and the energy costs (inclusive investment costs) by 4.6%. However, this result can only be achieved in reality if the current SGIP is extended to 2020, the investors consider at least a payback period of 10 years, and if the average fuel cell electric efficiencies reach 46% in 2020.

ZNEB runs for 2020 have not been considered since it is assumed that the market share of those buildings will not be influencing the CHP adoption. ZNEB have been considered in the 2030 runs.

5.3.2 Results for 2030

5.3.2.1 Cost minimization strategy

Run set (4c1) is the pure cost minimization case and shows 2482 MW of DG and CHP, but only ICEs and MTs with and without HX (see Table 5-4). The same is true if feed-in tariffs are allowed in run set (4c2). The electricity sales increase the costs savings further, but also increase the CO_2 emissions compared to the base case. Actually, all cost minimization runs for 2030, except the one with lower PV costs – run set (4c5), show higher *onsite* CO_2 emissions than the base case. This is partly the result of the low macro-grid CO_2 emissions in 2030. As described in chapter 4.3, an average 40% reduction in grid emissions is assumed for most 2030 optimization runs and this makes it difficult to reduce CO_2 emissions by CHP if cost minimization is considered. CO_2 reduction objectives show different results. Please compare Table 5-3, Table 5-5, and Table 5-6.

Table 5-3: 2030 result summary of run sets (4c) (source: DER-CAM runs)[8]

run	4a2	4a3	4c1	4c2	4c3	4c4	4c5	4c6
run description	2030 base case	2030 base case (2020 CO_2 values)	2030 (min US$)	2030 (min US$) + sales	2030 (min US$) + ZNEB	2030 (min US$) + FC20yrs + highFCeta	2030 (min US$) + FC20yrs + lowPV	2030 (min US$) + FC20yrs + highFCeta + 10yrPayback
available profiles	147	147	147	147	147	147	147	147
annual energy costs (bln $)	5.3	5.3	4.5	4.3	0.4	4.4	4.0	4.2
annual energy costs (%)	100.0	100.0	85.1	80.7	7.3	83.1	75.0	79.1
change in annual energy costs (%)			(14.9)	(19.3)	(92.7)	(16.9)	(25.0)	(20.9)
annual marginal CO_2 emissions (Mt/a)	14.5	21.8	15.6	16.4	24.2	16.0	13.5	14.7
annual marginal CO_2 emissions (%)	100.0	100.0	108.2	113.5	167.4	110.8	93.6	101.6
change in annual marginal CO_2 emssions (%)			8.2	13.5	67.4	10.8	(6.4)	1.6
installed DG capacities (MW)			2,528.3	3,043.8	5,434.8	2,829.3	2,273.2	3,939.1
installed DG capacities (GW)			2.5	3.0	5.4	2.8	2.3	3.9
installed PV capacities (MW)			496.8	979.4	25,280.0	556.6	3,629.7	2,681.4
installed PV capacities (GW)			0.5	1.0	25.3	0.6	3.6	2.7
installed Solar Thermal capacities (MW)			18.8	7.0	112.8	10.1	-	28.9
installed Solar Thermal capacities (GW)			0.0	0.0	0.1	0.0	-	0.0
electricity produced by DG (without PV) (GWh)			13,402.4	15,802.1	23,260.7	14,835.0	11,613.4	16,104.3
PV and DG sales (GWh)			-	1,713.1	48,253.8	-	-	-
PV sales (GWh)			-	1,713.1	48,162.0	-	-	-
cooling offset (GWh)			1,031.0	1,112.3	4,271.3	1,070.2	696.9	1,329.0
electric stationary storage (GWh)			0.4	0.5	1.6	0.4	0.4	0.3
heat storage (GWh)			-	0.0	0.2	-	0.1	-
DG capacity factor (%)			60.5	59.3	48,9	59.9	58.3	46.7

[8] Please note that cost minimization runs can show slightly higher energy costs as in the base case due to a 5% optimization accuracy - see run set (4c6).

Table 5-4: 2030 result summary of run sets (4)c (installed capacity, MW) (source: DER-CAM runs)

run	4a2	4a3	4c1	4c2	4c3	4c4	4c5	4c6
installed DG capacity (MW)	2030 base case	2030 base case (2020 CO2 values)	2030 (min US$)	2030 (min US$) + sales	2030 (min US$) + ZNEB	2030 (min US$) + FC20yrs + highFCeta	2030 (min US$) + FC20yrs + lowPV	2030 (min US$) + FC20yrs + highFCeta + 10yrPayback
total installed DG capacity (MW)	-	-	2,482.1	2,853.1	5,434.8	2,829.3	2,273.2	3,939.1
ICE	-	-	288.3	775.3	4,795.0	159.2	211.4	367.6
ICE-HX	-	-	858.4	132.6	524.0	1,396.9	818.0	2,669.3
GT	-	-	-	-	25.0	-	-	-
GT-HX	-	-	-	-	-	-	-	-
MT	-	-	63.4	103.4	-	69.8	16.2	27.5
MT-HX	-	-	1,272.1	1,841.8	90.8	1,195.6	1,227.7	793.9
FC	-	-	-	-	-	7.8	-	63.0
FC-HX	-	-	-	-	-	-	-	17.8
% ICE of DG	-	-	46.2	31.8	97.9	55.0	45.3	77.1
% GT of DG	-	-	-	-	0.5	-	-	-
% MT of DG	-	-	53.8	68.2	1.7	44.7	54.7	20.9
% FC of DG	-	-	-	-	-	0.3	-	2.0

In more detail, run set (4c3) represents full cost minimization with the ZNEB constraint. Very interesting is the finding that a lot of ICEs are adopted in this case. Most of the adopted technologies are ICEs without any waste heat utilization (see Table 5-4). To compensate for this natural gas consumption PV needs to be installed. This enormous amount of PV can create problems in terms of available space for PV (see also chapter 15.6 from the appendix). Thus, please note that ZNEB can increase *onsite* building CO_2 emissions if cost minimization is the main goal.

Run set (4c4) is an extension of run set (4c1) with a higher overall efficiency and a higher lifetime (20 years) for fuel cell technologies. While in (4c1) the installed DG capacity is 2482 MW it increases to 2829 MW in (4c4). However, please note that this case still shows higher CO_2 emissions compared to the base case.

Within run set (4c5) the costs for PV are reduced to $1500/kW. Compared to (4c1) there is a slight decrease of installed DG capacity from 2482 MW to 2273 MW. On the other hand, the amount of installed PV capacity increases from 496.8 to 3629.7 MW. An overall reduction of about 25% in costs and 6.4% in carbon emission is possible as well.

Run (4c6) considers a maximum payback period of 10 years for investments. An installed DG capacity of 3939.1 MW and a PV capacity of 2681.4 MW is the result of this optimization run set. However, please note that this case still shows higher CO_2 emissions as the base case.

5.3.2.2 CO_2 minimization strategy

In general, almost all CO_2 minimization runs for 2030 show *onsite* CO_2 reductions and costs reductions (except the ZNEB runs 4e5 and 4e6). Please note that all CO_2 emission runs assume a cost cap as already described earlier. All CO_2 minimization runs, except ZNEB, need to comply with a cost constraint forcing costs to be lower than the base case costs. As can be seen in Table 5-5 and Table 5-7, the adopted DG and CHP capacity is very limited for half of the run sets due to the low macro-grid CO_2 emissions as outlined earlier. The second contributing factor is the low payback period of 5 years for the commercial sector. Assuming a low payback period of 5 years and high grid de-carbonization in 2030 CHP never reaches more than roughly 1 GW in 2030 (see run set 4e7). However, assuming higher payback periods of 10 years or less grid de-carbonization in 2030 can elevate the installed CHP capacity up to roughly 2 GW in 2030 (see Table 5-8).

In detail, run (4e3) with a fuel cell lifetime of 20 years instead of 10 years, reduces the annual energy costs by 3.7% and the CO_2 emissions by 4.4% compared to the base case. The results are very interesting since the increased lifetime has no significant influence on the fuel cell adoption compared to run (4e1) and the adopted CHP capacity hovers around 683 MW in 2030. Since the team was curious about the influence of the 24h fuel cell constraint on the adoption pattern, run (4e4) was performed and surprisingly no major change in the fuel cell adoption could be observed. This 24h fuel cell constraint forces the fuel cell to run for at least 24 hours, if selected, to model SOFC behavior.

Table 5-5: 2030 result summary of run sets (4e1)-(4e7) (source: DER-CAM runs)

run	4e1	4e2	4e3	4e4	4e5	4e6	4e7
run description	2030 (min CO_2)	2030 (min CO_2) + sales	2030 (minCO_2) + FC20yrs	2030 (minCO_2) + FC20yrs + w/o FC constraint	2030 (minCO_2) + FC20yrs + ZNEB	2030 (minCO_2) + FC20yrs + ZNEB + w/o FC constraint	2030 (minCO_2) + FC20yrs + highFCeta
available profiles	147	147	147	147	147	147	147
annual energy costs (bln $)	5.1	5.1	5.1	5.1	8.5	8.4	5.0
annual energy costs (%)	96.4	96.2	96.3	96.7	159.7	158.6	94.4
change in annual energy costs (%)	(3.6)	(3.8)	(3.7)	(3.3)	59.7	58.6	(5.6)
annual marginal CO_2 emissions (Mt/a)	13.8	13.8	13.8	13.8	1.3	1.3	13.7
annual marginal CO_2 emissions (%)	95.6	95.4	95.6	95.7	9.2	9.2	95.1
change in annual marginal CO_2 emssions (%)	(4.4)	(4.6)	(4.4)	(4.3)	(90.8)	(90.8)	(4.9)
installed DG capacities (MW)	695.4	787.7	683.2	662.9	185.0	177.3	999.1
installed DG capacities (GW)	0.7	0.8	0.7	0.7	0.2	0.2	1.0
installed PV capacities (MW)	147.0	134.9	147.0	106.8	23,326.1	23,307.8	79.5
installed PV capacities (GW)	0.1	0.1	0.1	0.1	23.3	23.3	0.1
installed Solar Thermal capacities (MW)	472.7	494.2	472.8	501.6	19,177.3	19,016.4	341.2
installed Solar Thermal capacities (GW)	0.5	0.5	0.5	0.5	19.2	19.0	0.3
electricity produced by DG (without PV) (GWh)	4,073.9	4,524.0	4,018.2	3,855.6	322.0	322.0	6,244.4
PV and DG sales (GWh)	-	1.3	-	-	3,136.2	3,128.7	-
PV sales (GWh)	-	-	-	-	3,136.2	3,128.7	-
cooling offset (GWh)	-	13.9	-	-	508.3	468.3	28.3
electric stationary storage (GWh)	0.1	0.3	0.1	0.1	82.9	82.3	0.5
heat storage (GWh)	-	0.1	-	0.0	43.8	42.4	0.1
DG capacity factor (%)	66.9	65.6	66.9	66.4	19.9	20.7	71.3

Table 5-6: 2030 result summary of run sets (4e8)-(4e14) (source: DER-CAM runs)

run	4e8	4e9	4e10	4e11	4e12	4e13	4e14
run description	2030 (minCO_2) + FC20yrs + highFCeta + 2020gridCO2	2030 (minCO_2) + FC20yrs + lowPV	2030 (minCO_2) + FC20yrs + highFCeta + 10yrPayback	2030 (minCO_2) + FC20yrs + highFCeta + 10yrPayback + lowPV + sales	2030 (minCO_2) + FC20yrs + highFCeta + 10yrPayback + lowPV + ZNEB	2030 (minCO_2) + FC20yrs + highFCeta + 10yrPayback + smaller FC	2030 (minCO_2) + FC20yrs + highFCeta + 10yrPayback + small DG
available profiles	147	147	147	147	147	147	147
annual energy costs (bln $)	4.7	4.4	4.7	4.4	0.6	4.8	4.8
annual energy costs (%)	89.1	82.2	88.7	81.8	11.4	90.3	89.8
change in annual energy costs (%)	(10.9)	(17.8)	(11.3)	(18.2)	(88.6)	(9.7)	(10.2)
annual marginal CO_2 emissions (Mt/a)	18.9	11.7	10.8	6.5	6.4	10.4	10.2
annual marginal CO_2 emissions (%)	86.9	80.9	74.6	44.6	44.5	71.7	70.3
change in annual marginal CO_2 emssions (%)	(13.1)	(19.1)	(25.4)	(55.4)	(55.5)	(28.3)	(29.7)
installed DG capacities (MW)	2,176.5	727.2	2,003.0	2,087.0	1,856.2	2,076.4	2,086.7
installed DG capacities (GW)	2.2	0.7	2.0	2.1	1.9	2.1	2.1
installed PV capacities (MW)	266.4	3,658.5	4,048.1	20,720.7	25,380.3	4,665.9	4,860.3
installed PV capacities (GW)	0.3	3.7	4.0	20.7	25.4	4.7	4.9
installed Solar Thermal capacities (MW)	322.9	478.2	1,240.1	8,965.1	8,689.4	1,669.0	1,626.4
installed Solar Thermal capacities (GW)	0.3	0.5	1.2	9.0	8.7	1.7	1.6
electricity produced by DG (without PV) (GWh)	12,649.0	4,205.3	10,949.1	11,481.7	11,279.2	11,341.6	11,776.6
PV and DG sales (GWh)	-	-	-	8,757.7	33,432.6	-	-
PV sales (GWh)	-	-	-	8,757.7	33,432.6	-	-
cooling offset (GWh)	596.2	-	182.9	415.2	994.5	225.7	201.0
electric stationary storage (GWh)	1.1	1.8	7.8	39.8	39.5	12.6	13.0
heat storage (GWh)	0.0	0.0	2.0	22.0	22.8	4.4	4.0
DG capacity factor (%)	66.3	66.0	62.4	62.8	69.4	62.4	64.4

Table 5-7: 2030 result summary of run sets (4e1)-(4e7) (installed capacity, MW) (source: DER-CAM runs)

run	4e1	4e2	4e3	4e4	4e5	4e6	4e7
installed DG capacity (MW)	2030 (min CO2)	2030 (min CO2) + sales	2030 (minCO2) + FC20yrs	2030 (minCO2) + FC20yrs + w/o FC constraint	2030 (minCO2) + FC20yrs + ZNEB	2030 (minCO2) + FC20yrs + ZNEB + w/o FC constraint	2030 (minCO2) + FC20yrs + highFCeta
total installed DG capacity (MW)	695.4	787.7	683.2	662.9	185.0	177.3	999.1
ICE	-	-	-	-	-	-	-
ICE-HX	-	-	-	-	-	-	-
GT	-	-	-	-	-	-	-
GT-HX	-	-	-	-	-	-	-
MT	-	-	-	-	7.7	-	-
MT-HX	656.7	752.2	644.4	624.2	177.3	177.3	675.7
FC	-	-	-	-	-	-	58.8
FC-HX	38.8	35.5	38.8	38.8	-	-	264.7
% ICE of DG	-	-	-	-	-	-	-
% GT of DG	-	-	-	-	-	-	-
% MT of DG	94.4	95.5	94.3	94.2	100.0	100.0	67.6
% FC of DG	5.6	4.5	5.7	5.8	-	-	32.4

Table 5-8: 2030 result summary of run sets (4e8)-(4e14) (installed capacity, MW) (source: DER-CAM runs)

run	4e8	4e9	4e10	4e11	4e12	4e13	4e14
installed DG capacity (MW)	2030 (minCO2) + FC20yrs + highFCeta + 2020gridCO2	2030 (minCO2) + FC20yrs + lowPV	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback + lowPV + sales	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback + lowPV + ZNEB	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback + smaller FC	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback + small DG
total installed DG capacity (MW)	2,176.5	727.2	2,003.0	2,087.0	1,856.2	2,076.4	2,086.7
ICE	-	-	20.0	-	-	27.4	47.4
ICE-HX	-	-	-	10.4	14.1	-	-
GT	-	-	-	-	-	-	-
GT-HX	-	-	-	-	-	-	-
MT	0.6	-	0.9	17.2	0.4	-	-
MT-HX	1,769.3	685.2	893.4	410.2	412.9	882.1	861.9
FC	110.7	-	21.2	36.4	1.4	32.2	15.8
FC-HX	295.9	42.0	1,067.5	1,612.9	1,427.5	1,134.8	1,161.5
% ICE of DG	-	-	1.0	0.5	0.8	1.3	2.3
% GT of DG	-	-	-	-	-	-	-
% MT of DG	81.3	94.2	44.6	20.5	22.3	42.5	41.3
% FC of DG	18.7	5.8	54.4	79.0	77.0	56.2	56.4

Within run set (4e5), which is based on (4e3), it is assumed that all buildings should operate as a zero-net energy building under *onsite* building CO_2 minimization strategy. This run reduces the *onsite* carbon dioxide emissions by about 91% compared to the base case run (4a2). On the other hand, the costs are about 60% higher compared to the base case. A huge amount of PV, solar thermal, and electric storage needs to be installed to reach ZNEB status. Almost all installed natural gas fired units are with heat exchanger and waste heat utilization and a total of approx. 180 MW of CHP will be adopted, but the CHP capacity factor drops dramatically and reaches only roughly 20%. Please note that DER-CAM calculates the CO_2 emissions based on the energy used at the site/building. In other words, electricity purchased from the utility accounts for CO_2 emissions at the site. This implies that PV generated electricity sales do not reduce the carbon emissions at the site or building and this also drives onsite electric storage at CO_2 minimization strategies. Roughly 83 GWh of electric storage will be needed within this ZNEB run set (4e5).

Run set (4e6) just looks into the influence of the fuel cell operational constraint and finds no significant impact.

Run set (4e7) shows the results for a higher fuel cell efficiency as well as lifetime. An overall efficiency of 92%, where the electric efficiency is given as 60%, is assumed. The installed DG capacity increases to 999 MW while also the average DG capacity factor increases to 71.3%. The installed PV capacity is decreased to roughly 80 MW while the solar thermal capacity is also decreased to 341 MW. This case nicely shows the competition between CHP technologies and PV/solar thermal. However, please note the 590% increase of FC with HX compared to run set

(4e3) with lower fuel cell efficiency (see Table 5-7). As already mentioned, the low grid CO_2 emissions in 2030 make the adoption of CO_2 mitigating technologies more difficult. Run set (4e8) is based on the run set (4e7), but with the higher grid CO_2 emissions from 2020 (less grid de-carbonization). 2176.5 MW of DG capacity will be adopted within this run compared to 999.1 MW in (4e7). The installed PV capacity increases from 79.5 to 266.4 MW. In other words, lower grid de-carbonization will greatly support the CHP and PV adoption.

Run set (4e9) is based on (4e3) with halved PV costs of $1500/kW. The overall cost can be reduced from bln $5.1 to 4.4 while the CO_2 emissions decrease from 13.8 to 11.7 Mt/a as well. While the installed DG capacity increases slightly from 683 to 727 MW the installed PV capacity jumps from 147 to 3659 MW.

Run set (4e10) is based on (4e7) with the extension that the maximum payback period is defined as 10 years instead of 5 years. While the installed natural gas fired DG capacity increases from 991 to 2003 MW the installed PV capacity increases from 79.5 to 4048.1 MW.

Run set (4e11) is based on (4e10) with lower PV costs of $1500/kW and enabled electricity sales for natural gas fired DG and PV. A significant amount of PV and solar thermal capacity is installed in this case, 21 GW and 9 GW, respectively. Interestingly, the total amount of natural gas fired DG is almost unchanged, and as can be seen from Table 5-8, more FC-HX will be installed. In this case the amount of MT-HX is about half of run set (4e10).

Run set (4e12) is based on (4e11) and it is assumed that all buildings need to operate as a zero-net energy building under *onsite* building CO_2 minimization strategy. This run set deserves special attentions since it is the first ZNEB run that demonstrates an enormous cost and CO_2 saving for the considered commercial buildings. Assuming high fuel cell efficiencies, 10 year payback periods for investments, very low PV prices, and ZNEB constraints, the buildings can reduce energy costs by almost 89% combined with an almost 56% onsite CO_2 reduction. Furthermore, the adopted natural gas fired DG technologies show only a moderate decline and seem to be very important for onsite energy generation since all energy sold to the grid originates from PV sales (please refer to Table 5-6). However, cost reductions of 89% and the enormous amount of PV sales to the grid might trigger also lower utility tariffs and this dynamic behavior might mitigate the cost reductions. Such effects are out of the scope of DER-CAM and would need different simulation approaches.

Run set (4e13) and (4e14) consider smaller FC and DG units and find no significant change in DG adoption compared to run set (4e10), which was used as basis for these runs. In detail, run set (4e13) uses a smallest FC unit size of 60 kW and run set (4e14) assumes smallest DG units of 25kW for all technologies.

From the author's perspective SGIP is not rational for 2030, and therefore, no such cases are considered in 2030.

5.4 Regional distribution of NOx emissions

5.4.1 Year 2020

Assuming that all natural gas fired ICEs and MTs are complying with the current NOx standards of 0.07 lb/MWh_e (=0.03 kg/MWh_e) and that natural gas FCs emit roughly 0.05 lb/MWh_e (= 0.02 kg/MWh_e) a total amount of 371 tNOx/year will be emitted from running these technologies in the most optimistic run set (4d4). Please note that neither boiler nor any central power plant offsets are considered in these calculations.

Almost 60% of all DER related NOx emissions occur in the heavily populated forecasting climate zones 5 (San Francisco Bay Area), 9 (Los Angeles County), and 13 (San Diego). However, almost all NOx emissions originated from natural gas operated fuel cells (see Figure 5-4). Please note that run set (4d4) considers the SGIP.

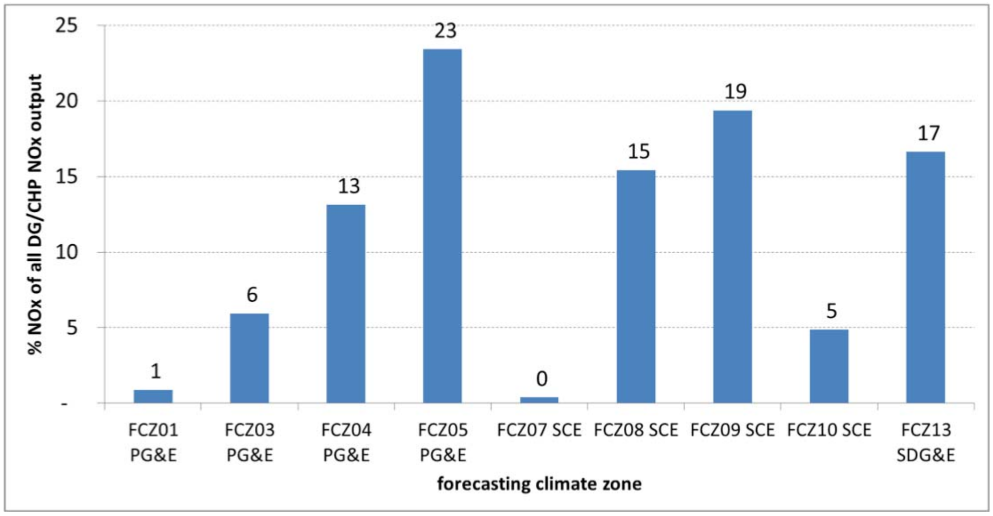

Figure 5-3: Regional DER NOx emissions for most optimistic case (4d4) (source: DER-CAM runs)

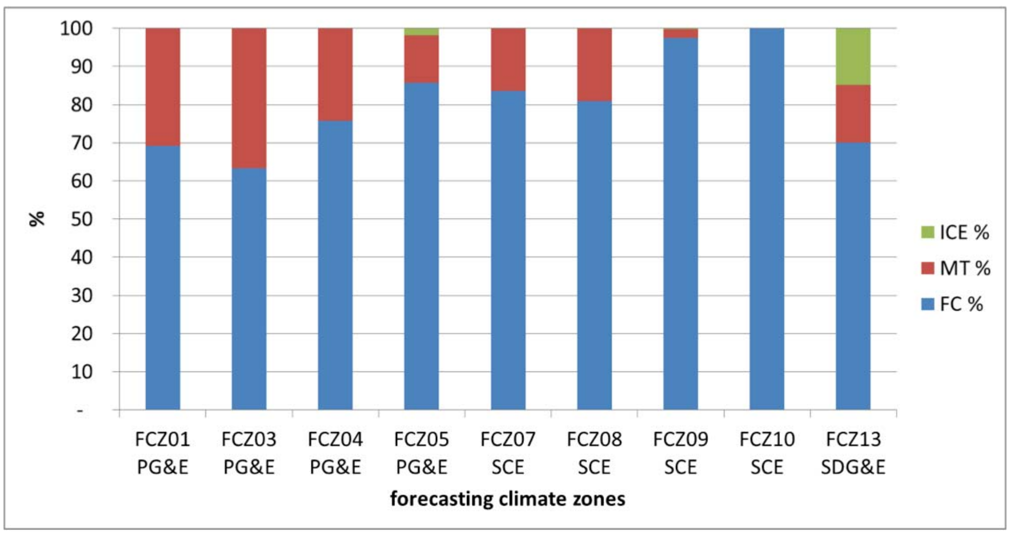

Figure 5-4: Composition of regional DER NOx emissions for most optimistic case (4d4) (source: DER-CAM runs)

About 94% of the installed DG capacities are systems with heat exchanger.

5.4.2 Year 2030

Again, assuming that all natural gas fired ICEs and MTs are complying with the current NOx standards of 0.07 lb/MWh_e (= 0.03 kg/MWh_e) and that natural gas FCs emit roughly 0.05 lb/MWh_e (= 0.02 kg/MWh_e) a total amount of 267 tNOx/year will be emitted from running these technologies in run set (4e10). Please note that neither boiler nor any central power plant offsets are considered in these calculations.

63% of all DER related NOx emissions occur in the heavy populated forecasting climate zones 5 (San Francisco Bay Area), 9 (Los Angeles County), and 13 (San Diego). However, in contrast to 2020 now FCs represent only 50% of the adopted technologies and MTs are very dominant due to the missing SGIP in 2030 (see Figure 5-6).

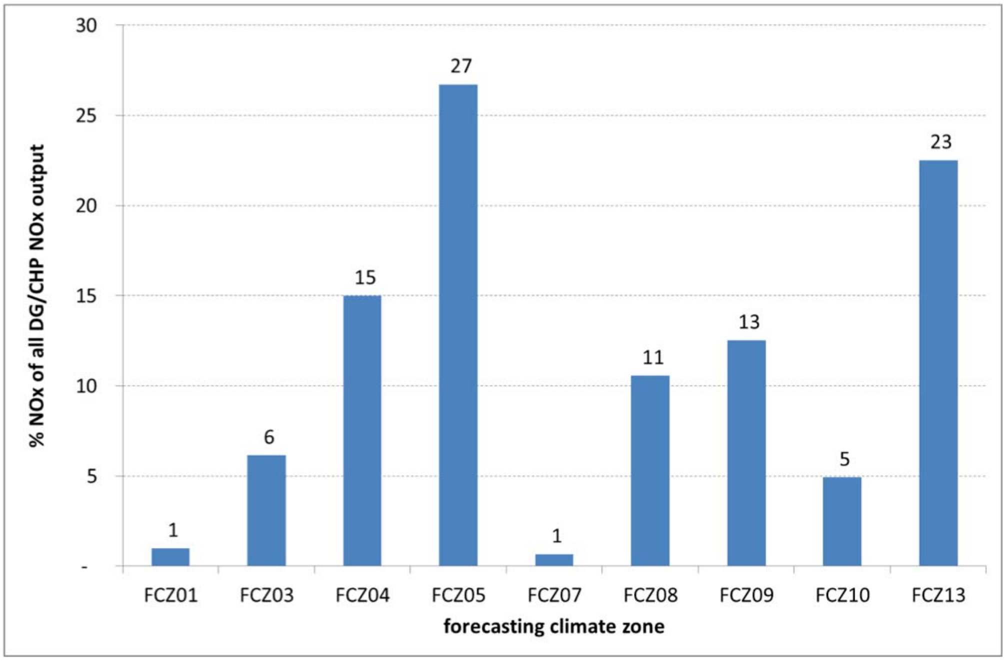

Figure 5-5: Regional NOx emissions for run set (4e10) (source: DER-CAM runs)

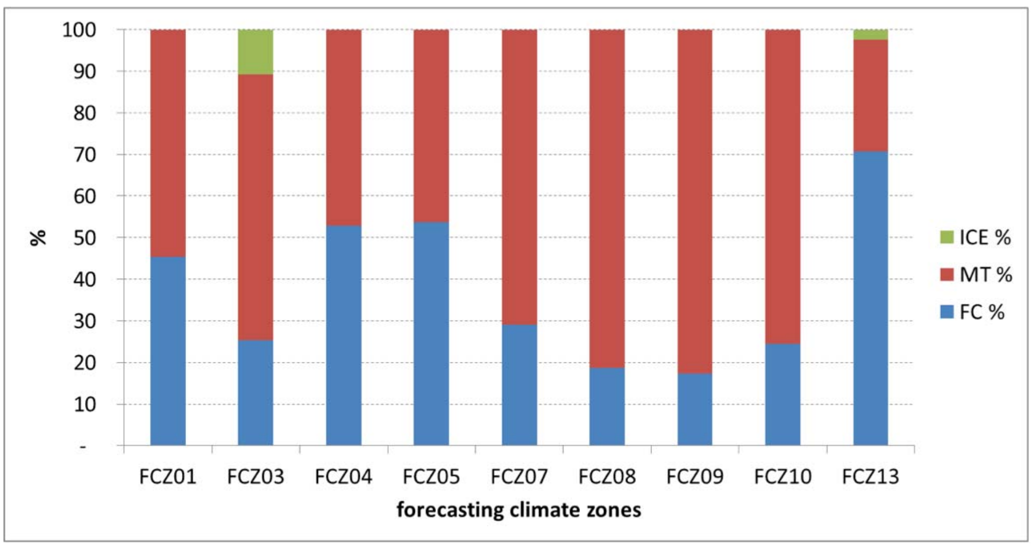

Figure 5-6: Composition of regional DER NOx emissions for run set (4e10) (source: DER-CAM runs)

About 98% of the installed DG capacities are systems with heat exchanger.

5.5 The impact of PDP on DER adoption

Several sensitivity runs regarding the influence of peak-day-pricing on DER adoption were analyzed within the forecasting climate zone FCZ05. Please note that DER-CAM can only roughly simulate the PDP influence since the PDP scheme represents a non-linear mathematical problem where the tariffs depend on the effective electricity purchases from the utility. It would be necessary to completely reprogram DER-CAM and even then there would be no guarantee that the PDP problem could be solved from a mathematical point of view.

Thus, for the FCZ05 sensitivity runs following assumptions were used:

- PDP events can only happen between noon and 6pm in summer months (May to October)
- 15 PDP events total
- no PDP credit is applied
- PDP energy charge applies to all energy purchase; in reality the PDP would only apply to purchases above the capacity reserve (for more information please refer to appendix 12.6.3.2)

Based on these assumptions DER-CAM will overestimate the impact of PDP on DER adoption.

5.5.1 PDP sensitivity runs for 2020

5.5.1.1 Run set (4d3)

Within zone FCZ05 the installed natural gas fired DG capacity increases by 14.2% due to PDP. The installed CHP capacity increases by 12% and shows less increase as technologies without HX. However, PDP mostly increases the PV and solar thermal adoption. The installed PV capacity increases by 342% due to PDP (see Table 5-9).

Table 5-9: Impact of PDP on run set (4d3) in FCZ05

summary per supplier / climate zone	FCZ05 PG&E without PDP	FCZ05 PG&E with PDP	change (in %)
installed DG capacity (MW)	330.1	377.1	14.2%
installed CHP capacity (MW)	330.1	369.9	12.1%
installed PV capacity (MW)	25.4	112.1	342.1%
installed Solar Thermal capacity (MW)	39.0	61.3	57.0%
DG capacity factor (%)	77.2	80.1	3.6%

5.5.2 PDP sensitivity runs for 2030

5.5.2.1 Run set (4e7)

In contrast to the previous run, run set (4e7) shows a different pattern due to PDP. The overall natural gas fired DG equipment (with and without HX) decreases by about 2.8%. On the other hand, the CHP capacity shows an increase by 12.3%.

The increase in the adopted PV and solar thermal capacity seems to be very unrealistic and might conflict with the maximum available space for solar thermal and PV in the commercial buildings (see Table 5-10).

Table 5-10: Impact of PDP on run set (4e7) in FCZ05

summary per supplier / climate zone	FCZ05 PG&E without PDP	FCZ05 PG&E with PDP	change (in %)
installed DG capacity (MW)	437.6	425.2	-2.8%
installed CHP capacity (MW)	378.8	425.2	12.3%
installed PV capacity (MW)	17.5	729.8	4060.6%
installed Solar Thermal capacity (MW)	94.3	543.2	476.3%
DG capacity factor (%)	66.9	72.1	7.8%

5.5.2.2 Run set (4e10)

Run set (4e10) shows less impact on PV adoption than on natural gas fired DG adoption. Due to the already high levels of PV and solar thermal adoption without PDP, the PV and solar thermal capacity increase might be limited (see Table 5-11).

Table 5-11: Impact of PDP on run set (4e10) in FCZ05

summary per supplier / climate zone	FCZ05 PG&E without PDP	FCZ05 PG&E with PDP	change (in %)
installed DG capacity (MW)	561.5	680.4	21.2%
installed CHP capacity (MW)	561.5	635.4	13.2%
installed PV capacity (MW)	855.2	1,025.7	19.9%
installed Solar Thermal capacity (MW)	259.1	402.8	55.5%
DG capacity factor (%)	61.4	58.8	-4.2%

All of these sensitivity runs show different patterns due to PDP. Due to the limited capabilities of the current DER-CAM version further research might be needed to derive a conclusive result.

6 Results for the restaurant sector

6.1 2020 results

The results for the cost minimization cases with a maximum payback period of 5 years for the considered restaurants do not show any improvement regarding the reduction of carbon emissions. The minimize cost cases with 5 year payback period reduce the costs between 5.7% and 4.5% while the annual marginal carbon emissions increase by up to 2.4%. Only assuming a 10 year payback period for investments shows a 10% cost reduction combined with a 6.1% CO_2 reduction.

The minimize carbon cases with 5 year payback period can decrease the costs up to 4.0%, but the reduction in CO_2 is negligible. Again, only a 10 year payback period for investments delivers a 14.5% reduction in CO_2 emissions and a 5.9% reduction in energy costs.

Table 6-1: 2020 result summary of run sets (4b) and (4d) for the considered restaurants (source: DER-CAM runs)[9]

run	4a1	4b1	4b2	4b3	4b4	4d1	4d2	4d3	4d4
REST - run description	base case	2020 (min US$)	2020 (min US$) + SGIP	2020 (min US$) + high FC efficiency + SGIP	2020 (min US$) + high FC efficiency + 10yrs payback + SGIP	2020 (min CO2)	2020 (min CO2) + SGIP	2020 (min CO2) + high FC efficiency + SGIP	2020 (min CO2) + high FC efficiency + 10yrs payback + SGIP
available profiles	9	9	9	9	9	9	9	9	9
annual energy costs (mln $)	342.4	327.1	322.8	322.9	308.2	328.8	343.1	343.1	322.2
annual energy costs (%)	100.0	95.5	94.3	94.3	90.0	96.0	100.2	100.2	94.1
change in annual energy costs (%)		(4.5)	(5.7)	(5.7)	(10.0)	(4.0)	0.2	0.2	(5.9)
annual marginal CO_2 emissions (kt/a)	1,440.3	1,467.1	1,474.6	1,474.8	1,352.7	1,439.1	1,443.5	1,443.5	1,230.9
annual marginal CO_2 emissions (%)	100.0	101.9	102.4	102.4	93.9	99.9	100.2	100.2	85.5
change in annual marginal CO_2 emssions (%)		1.9	2.4	2.4	(6.1)	(0.1)	0.2	0.2	(14.5)
installed DG capacities (MW)		48.7	69.6	69.6	96.8	48.7	-	-	124.7
installed DG capacities (GW)		0.0	0.1	0.1	0.1	0.0	-	-	0.1
installed PV capacities (MW)		-	5.4	5.1	124.4	6.9	-	-	189.5
installed PV capacities (GW)		-	0.0	0.0	0.1	0.0	-	-	0.2
installed Solar Thermal capacities (MW)		8.3	2.0	2.0	23.1	10.1	2.4	2.4	51.3
installed Solar Thermal capacities (GW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
electricity produced by DG (without PV) (GWh)		349.6	487.5	487.1	479.0	292.8	-	-	506.5
PV and DG sales (GWh)		-	-	-	-	-	-	-	-
PV sales (GWh)		-	-	-	-	-	-	-	-
cooling offset (GWh)		-	-	-	-	-	-	-	-
electric stationary storage (GWh)		0.1	0.1	0.1	-	0.1	-	-	0.2
heat storage (GWh)		-	-	-	-	-	-	-	0.1
DG capacity factor (%)		81.9	80.0	79.9	56.5	68.6	-	-	46.3

The SGIP does not impact the results at all in 2020 as can be seen from Table 6-2. The most influential factor is the payback period. The most important DG technologies are ICEs without HX and MTs with HX. In an optimistic case, roughly 125 MW of MT-HX will be adopted in California's large restaurants.

[9] Please note that CO_2 minimization runs can show slightly higher CO_2 emissions as in the base case due to a 5% optimization accuracy - see run set (4d2) and (4d3).

Table 6-2: 2020 result summary of run sets (4b) and (4d) in the restaurant sector (installed DG capacity, MW) (source: DER-CAM runs)

run	4a1	4b1	4b2	4b3	4b4	4d1	4d2	4d3	4d4
installed DG capacity (kW) restaurants only	base case	2020 (min US$)	2020 (min US$) + SGIP	2020 (min US$) + high FC efficiency + SGIP	2020 (min US$) + high FC efficiency + 10yrs payback + SGIP	2020 (min CO2)	2020 (min CO2) + SGIP	2020 (min CO2) + high FC efficiency + SGIP	2020 (min CO2) + high FC efficiency + 10yrs payback + SGIP
total installed DG capacity (kW)	-	48,720	69,600	69,600	96,780	48,720	-	-	124,740
ICE	-	27,000	27,000	27,000	75,060	-	-	-	-
ICE-HX	-	-	-	-	21,720	-	-	-	-
GT	-	-	-	-	-	-	-	-	-
GT-HX	-	-	-	-	-	-	-	-	-
MT	-	-	-	-	-	-	-	-	-
MT-HX	-	21,720	42,600	42,600	-	48,720	-	-	124,740
FC	-	-	-	-	-	-	-	-	-
FC-HX	-	-	-	-	-	-	-	-	-
% ICE of DG	-	55.4	38.8	38.8	100.0	-	-	-	-
% GT of DG	-	-	-	-	-	-	-	-	-
% MT of DG	-	44.6	61.2	61.2	-	100.0	-	-	100.0
% FC of DG	-	-	-	-	-	-	-	-	-

6.2 2030 results

6.2.1 Cost minimization strategy

All cost minimization cases show increased *onsite* CO_2 emissions, except the case (4c5) with lower PV costs of $1500/kW.

From the authors' perspective SGIP is not rational for 2030 therefore no such run set was done.

Table 6-3: 2030 result summary of run sets (4c) for the considered restaurants (source: DER-CAM runs)

run	4a2	4a3	4c1	4c2	4c3	4c4	4c5	4c6
REST - run description	2030 base case	2030 base case (2020 CO2 values)	2030 (min US$)	2030 (min US$) + sales	2030 (min US$) + ZNEB	2030 (min US$) + FC20yrs + highFCeta	2030 (min US$) + FC20yrs + lowPV	2030 (min US$) + FC20yrs + highFCeta + 10yrPayback
available profiles	9	9	9	9	9	9	9	9
annual energy costs (mln $)	342.4	342.4	304.0	331.9	63.6	302.0	286.2	293.0
annual energy costs (%)	100.0	100.0	88.8	96.9	18.6	88.2	83.6	85.6
change in annual energy costs (%)			(11.2)	(3.1)	(81.4)	(11.8)	(16.4)	(14.4)
annual marginal CO_2 emissions (kt/a)	1,076.2	1,440.3	1,191.1	1,164.3	1,303.2	1,174.6	1,061.0	1,085.2
annual marginal CO_2 emissions (%)	100.0	100.0	110.7	108.2	121.1	109.1	98.6	100.8
change in annual marginal CO_2 emssions (%)			10.7	8.2	21.1	9.1	(1.4)	0.8
installed DG capacities (MW)			96.8	68.7	201.6	96.8	94.9	212.6
installed DG capacities (GW)			0.1	0.1	0.2	0.1	0.1	0.2
installed PV capacities (MW)			41.1	0.7	1,524.4	53.4	172.4	228.9
installed PV capacities (GW)			0.0	0.0	1.5	0.1	0.2	0.2
installed Solar Thermal capacities (MW)			2.0	2.1	41.9	2.0	-	0.2
installed Solar Thermal capacities (GW)			0.0	0.0	0.0	0.0	-	0.0
electricity produced by DG (without PV) (GWh)			654.1	372.2	929.6	640.6	446.5	796.6
PV and DG sales (GWh)			-	1.3	2,589.8	-	-	-
PV sales (GWh)			-	1.3	2,589.8	-	-	-
cooling offset (GWh)			-	-	115.7	-	-	-
electric stationary storage (GWh)			0.1	0.1	0.4	0.1	0.1	0.1
heat storage (GWh)			-	-	0.1	-	-	-
DG capacity factor (%)			77.1	61.8	52.6	75.6	53.7	42.8

Within the cost minimization runs the considered amount of DG is between 68.7 and 201.6 MW and fuel cells play no role and micro-turbines with HX are the most prominent technology.

Table 6-4: 2030 result summary of run set (4c) for the considered restaurants (installed DG capacity, MW) (source: DER-CAM runs)

run	4a2	4a3	4c1	4c2	4c3	4c4	4c5	4c6
installed DG capacity (kW) restaurants only	2030 base case	2030 base case (2020 CO2 values)	2030 (min US$)	2030 (min US$) + sales	2030 (min US$) + ZNEB	2030 (min US$) + FC20yrs + highFCeta	2030 (min US$) + FC20yrs + lowPV	2030 (min US$) + FC20yrs + highFCeta + 10yrPayback
total installed DG capacity (kW)	-	-	96,780	68,700	201,600	96,780	94,860	212,580
ICE	-	-	-	-	201,600	-	-	42,600
ICE-HX	-	-	20,880	-	-	-	-	1,920
GT	-	-	-	-	-	-	-	-
GT-HX	-	-	-	-	-	-	-	-
MT	-	-	25,260	46,980	-	25,260	-	25,260
MT-HX	-	-	50,640	21,720	-	71,520	94,860	142,800
FC	-	-	-	-	-	-	-	-
FC-HX	-	-	-	-	-	-	-	-
% ICE of DG	-	-	21.6	-	100.0	-	-	20.9
% GT of DG	-	-	-	-	-	-	-	-
% MT of DG	-	-	78.4	100.0	-	100.0	100.0	79.1
% FC of DG	-	-	-	-	-	-	-	-

6.2.2 CO_2 minimization strategy

Most carbon minimization runs show no DG/CHP adoption. MTs can reach 47 MW in the run set (4e10) and FCs can reach 57.1MW in run set (4e14). Run set (4e8) is not representative since it assumes less grid de-carbonization in 2030.

Please note that the smallest CHP unit in this work is 60 kW, with the exception of run set (4e14). In (4e14), the size of the units was reduced to 25 kW, and this lead to FC adoption (see Table 6-7).

Table 6-5: 2030 result summary of run set (4e1)-(4e7) for the restaurant sector (source: DER-CAM runs)

run	4e1	4e2	4e3	4e4	4e5	4e6	4e7
REST - run description	2030 (min CO2)	2030 (min CO2) + sales	2030 (minCO2) + FC20yrs	2030 (minCO2) + FC20yrs + w/o FC constraint	2030 (minCO2) + FC20yrs + ZNEB	2030 (minCO2) + FC20yrs + ZNEB + w/o FC constraint	2030 (minCO2) + FC20yrs + highFCeta
available profiles	9	9	9	9	9	9	9
annual energy costs (mln $)	342.1	342.1	342.1	342.1	468.8	458.5	342.1
annual energy costs (%)	99.9	99.9	99.9	99.9	136.9	133.9	99.9
change in annual energy costs (%)	(0.1)	(0.1)	(0.1)	(0.1)	36.9	33.9	(0.1)
annual marginal CO_2 emissions (kt/a)	1,073.4	1,073.9	1,073.4	1,073.4	379.8	379.8	1,073.4
annual marginal CO_2 emissions (%)	99.7	99.8	99.7	99.7	35.3	35.3	99.7
change in annual marginal CO_2 emssions (%)	(0.3)	(0.2)	(0.3)	(0.3)	(64.7)	(64.7)	(0.3)
installed DG capacities (MW)	-	-	-	-	-	-	-
installed DG capacities (GW)	-	-	-	-	-	-	-
installed PV capacities (MW)	-	-	-	-	1,571.2	1,636.4	-
installed PV capacities (GW)	-	-	-	-	1.6	1.6	-
installed Solar Thermal capacities (MW)	9.1	7.5	9.1	9.1	1,228.4	1,157.9	9.1
installed Solar Thermal capacities (GW)	0.0	0.0	0.0	0.0	1.2	1.2	0.0
electricity produced by DG (without PV) (GWh)	-	-	-	-	-	-	-
PV and DG sales (GWh)	-	-	-	-	713.0	711.9	-
PV sales (GWh)	-	-	-	-	713.0	711.9	-
cooling offset (GWh)	-	-	-	-	57.0	31.2	-
electric stationary storage (GWh)	0.0	0.0	0.0	0.0	4.5	4.3	0.0
heat storage (GWh)	-	-	-	-	2.9	2.1	-
DG capacity factor (%)	-	-	-	-	-	-	-

Table 6-6: 2030 result summary of run set (4e8)-(4e15) for the restaurant sector (source: DER-CAM runs)

run	4e8	4e9	4e10	4e11	4e12	4e13	4e14
REST - run description	2030 (minCO2) + FC20yrs + highFCeta + 2020gridCO2	2030 (minCO2) + FC20yrs + lowPV	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback + lowPV + sales	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback + lowPV + ZNEB	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback + smaller FC	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback + small DG
available profiles	9	9	9	9	9	9	9
annual energy costs (mln $)	307.5	307.5	317.8	44.0	(2.0)	322.9	312.9
annual energy costs (%)	89.8	89.8	92.8	12.9	(0.6)	94.3	91.4
change in annual energy costs (%)	(10.2)	(10.2)	(7.2)	(87.1)	(100.6)	(5.7)	(8.6)
annual marginal CO_2 emissions (kt/a)	1,381.0	976.4	927.3	379.2	379.2	866.6	782.0
annual marginal CO_2 emissions (%)	95.9	67.8	86.2	35.2	35.2	80.5	72.7
change in annual marginal CO_2 emssions (%)	(4.1)	(32.2)	(13.8)	(64.8)	(64.8)	(19.5)	(27.3)
installed DG capacities (MW)	94.9	-	47.0	-	-	-	89.7
installed DG capacities (GW)	0.1	-	0.0	-	-	-	0.1
installed PV capacities (MW)	45.7	144.0	206.0	5,022.1	8,802.9	275.3	350.2
installed PV capacities (GW)	0.0	0.1	0.2	5.0	8.8	0.3	0.4
installed Solar Thermal capacities (MW)	5.9	53.5	125.5	1,080.0	949.5	154.2	123.5
installed Solar Thermal capacities (GW)	0.0	0.1	0.1	1.1	0.9	0.2	0.1
electricity produced by DG (without PV) (GWh)	572.9	-	124.0	-	-	-	576.4
PV and DG sales (GWh)	-	-	-	2,637.4	16,573.4	-	-
PV sales (GWh)	-	-	-	2,637.4	16,573.4	-	-
cooling offset (GWh)	-	-	-	17.5	90.8	-	-
electric stationary storage (GWh)	0.2	0.0	0.4	4.2	4.0	0.7	1.1
heat storage (GWh)	-	-	0.1	2.0	2.1	0.1	0.1
DG capacity factor (%)	68.9	-	30.1	-	-	-	73.4

Table 6-7: 2030 result summary of run set (4e8)-(4e14) for the considered restaurants (installed DG capacity, kW) (source: DER-CAM runs)

run	4e8	4e9	4e10	4e11	4e12	4e13	4e14
installed DG capacity (kW) restaurants only	2030 (minCO2) + FC20yrs + highFCeta + 2020gridCO2	2030 (minCO2) + FC20yrs + lowPV	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback + lowPV + sales	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback + lowPV + ZNEB	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback + smaller FC	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback + small DG
total installed DG capacity (kW)	94,860	-	46,980	-	-	-	89,700
ICE	-	-	-	-	-	-	-
ICE-HX	-	-	-	-	-	-	-
GT	-	-	-	-	-	-	-
GT-HX	-	-	-	-	-	-	-
MT	-	-	-	-	-	-	-
MT-HX	94,860	-	46,980	-	-	-	32,600
FC	-	-	-	-	-	-	-
FC-HX	-	-	-	-	-	-	57,100
% ICE of DG	-	-	-	-	-	-	-
% GT of DG	-	-	-	-	-	-	-
% MT of DG	100.0	-	100.0	-	-	-	36.3
% FC of DG	-	-	-	-	-	-	63.7

7 High level comparison of 2020 and 2030 results

The most optimistic run set (4d4) for 2020 and for 2030 (4e10) are depicted in this section for comparison reasons.

As can be seen from Figure 7-1 and Figure 7-2 PG&E, and forecasting climate zone 5 (San Francisco Bay Area) show the most CHP adoption followed by SCE forecasting zone 9 (north of L.A.) in 2020. The total amount of CHP for the most optimistic case in 2020 is around 2385 MW and 2116 MW of FC with HX will be installed.

In 2030, PG&E and forecasting climate zone 5 again show the highest CHP adoption potential (see Figure 7-3 and Figure 7-4). However, in 2030 customers in the small SDG&E service territory (forecasting climate zone 13) seem to be the second largest adopter of CHP in California. The total CHP capacity is 1961 MW in 2030.

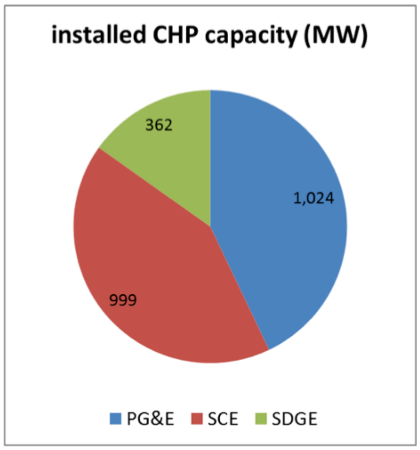

Figure 7-1: Installed CHP capacity by utility service territory, for most optimistic case (4d4), 2020 (source: DER-CAM runs)

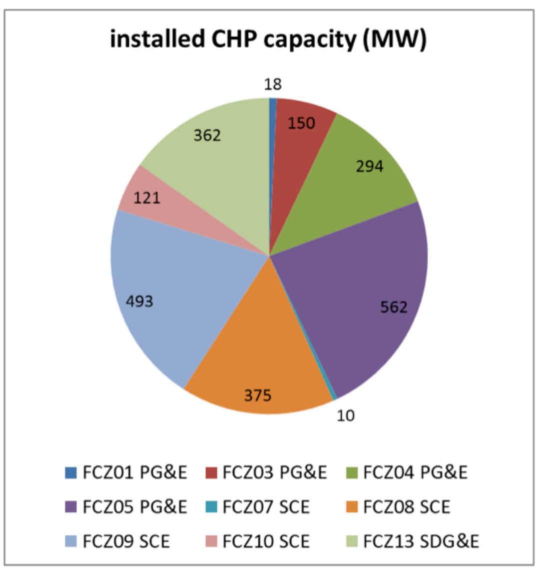

Figure 7-2: Installed CHP capacity by forecasting climate zone, most optimistic case (4d4), 2020 (source: DER-CAM runs)

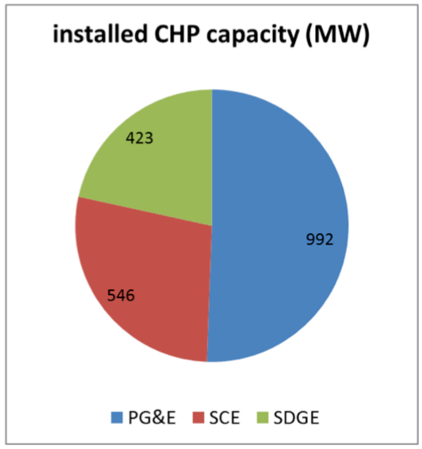

Figure 7-3: Installed CHP capacity by utility service territory, run set case (4e10) for 2030 (source: DER-CAM runs)

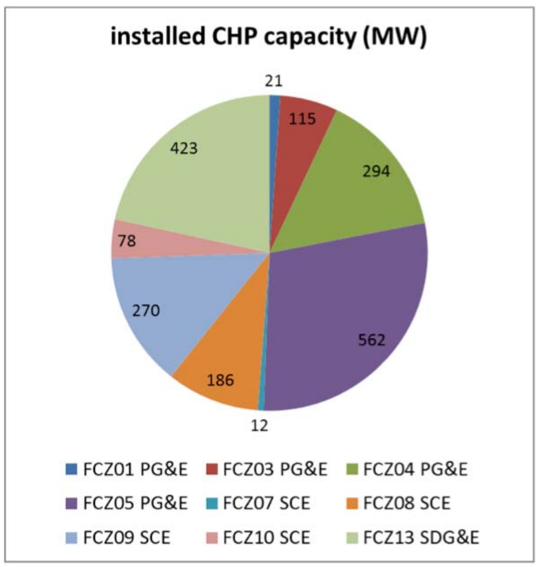

Figure 7-4: Installed CHP capacity by forecasting climate zone, run set (4e10) for 2030 (source: DER-CAM runs)

Due to the lower grid CO_2 emissions in 2030, the adopted CHP capacity in 2030 can be lower than in 2020. Only, if the investors assume a 10 year payback period for their investments, and the fuel cells reach 60% electric efficiency, and last for 20 years will the adopted CHP capacity (MT-HX, FC-HX) reach roughly 2.0 GW in 2030 (run set (4e10)).

The most optimistic case for 2020 – run set (4d4) - shows about 2.1 GW of FCs with HX and the case for 2030 – run set (4e10) - shows about 1.1 GW of FCs with HX, which effectively means a 50% reduction of FCs with HX by 2030 due to grid de-carbonization. Please note that the 2030 run set (4e10) does not consider any SGIP.

8 Impact of building stock growth

As the CEUS database is based on the 2006 building stock size all our optimization runs are based on the 2006 building stock as well. An average annual net growth of 1.0% can be assumed between 2010 and 2035 within the commercial floor space (EIA, 2012). Considering this annual growth between 2006 and 2020, respectively 2030, and assuming that this is growth is evenly distributed over all building categories, the results from all DER-CAM runs can be multiplied directly by 1.27 ($=(1+0.01)^{(2030-2006)}$) $= 1.01^{24}$ to arrive at the total 2030 results. To calculate the 2020 building stock, a multiplier of 1.15 can be used.

8.1 2020

Considering the building stock growth the most optimistic CHP potential in 2020 will be 2.7 GW based on the results from run set (4d4). However, this result assumes a SGIP in 2020, 46% electric efficiency for the fuel cells, a payback period for investments of 10 years, and a CO_2 minimization strategy for building owners.

8.2 2030

Considering the building stock growth the CHP potential in 2030 will be 2.5 GW based on the results from run set (4e10). However, this result assumes 60% electric efficiency and 20 year life time for the fuel cells, a payback period for investments of 10 years, and a CO_2 minimization strategy for building owners.

Finally, a reminder that this work does not consider the whole commercial sector in CA as described in chapter 4.1. The used commercial building stock roughly represents 37% of the state wide commercial sector electricity consumption. Thus, the 2.5 GW of CHP in 2030 contribute 38% to Governor Brown's research agenda of 6 500 MW of additional CHP in 2030 (Neff, 2012).

9 Conclusions

Governor Brown's research priorities include an additional 6.5 GW of CHP by 2030. As of 2009, roughly 0.25 GW of small natural gas and biogas fired CHP is documented by the Self-Generation Incentive Program (SGIP) database. The SGIP is set to expire, and the anticipated grid de-carbonization based on the development of 20 GW of renewable energy will influence the CHP adoption. Thus, an integrated optimization approach was chosen that allows optimizing the adoption of DER as PV, CHP, storage technologies, etc. in the California commercial sector from the building owners' perspective. To solve this DER adoption problem the Distributed Energy Resources Customer Adoption Model (DER-CAM) has been used. The focus of this work is on commercial sector CHP, especially above 50 to 100 kW peak electricity load since it is widely overlooked. In order to analyze the role of DER in CO_2 reduction, 147 representative sites in different climate zones were selected from the California Commercial End Use Survey (CEUS). And since restaurant consumes roughly 25% of the natural gas in California, special attention was paid to this sector. About 8000 individual optimization runs have been performed. Two major customer adoption strategies were simulated with DER-CAM:

- Primary goal of the DER adoption is *cost reduction* and
- Primary goal of DER adoption is *CO_2 reduction*.

The 2020 cost reduction runs do not show major fuel cell or CHP adoption, which could significantly reduce the environmental impact. The 2030 cost reduction runs show CHP adoption, but no significant CHP enabled fuel cell adoption, and therefore, also no reduction in environmental impacts. Based on these findings, only CO_2 reduction strategies should be pursuit and implemented.

The extension of the current SGIP until 2020 shows promising results in terms of CHP fuel cell adoption. If investors allow a 10 year payback period, the fuel cells reach 46% electric efficiency and sustain 10 years without a stack replacement, and CO_2 reduction is the prime goal roughly 2.1 GW of CHP enabled fuel cells are possible in the currently existing commercial buildings with electric peak loads above 100 kW (50 kW for restaurants). 125 MW of CHP enabled micro-turbines could help the restaurant sector to reduce the CO_2 emissions by 15% and save costs of 6%. Considering the building stock growth the fuel cell adoption can reach 2.4 GW. Besides fuel cells also CHP enabled micro-turbines play a role and the total CHP capacity, considering the building stock growth, can reach 2.7 GW in 2020. These CHP potential in combination with PV and solar thermal reduces the CO_2 emissions by 37% and saves the building owners 5% in total building energy costs. Due to this high fuel cell adoption rate, NOx emissions do not seem to pose a problem. A rough simulation of the recently introduced Peak Day Pricing scheme in the San Francisco Bay Area indicates increased CHP potential. However, further research will be needed to confirm this result.

The 2030 results are more complicated. Due to the missing SGIP in 2030 and expected grid de-carbonization, the runs show less fuel cells in 2030 compared to 2020. Assuming a 60% electric efficiency and 20 year life time for fuel cells, a payback period of 10 years, and a CO_2 minimization strategy, 1 GW of CHP enabled fuel cells are possible in the considered existing commercial building stock. The CHP enabled fuel cell adoption can reach more than 1.4 GW if zero net energy buildings are considered. Thus, in ZNEB, PV and solar thermal adoption is high, but CHP enabled fuel cell adoption will also increase, and this is an indication that natural gas fired engines will not be eliminated in a ZNEB environment. 47 MW of CHP enabled micro-turbines could help the restaurant sector to reduce the CO_2 emissions by 14% and save costs of 7%. Allowing smaller CHP units of 25 kW could help the CHP adoption in the restaurant sector, and 57 MW of CHP enabled fuel cells would also be possible. Considering the building stock growth, the fuel cell adoption can go up to 1.3 GW, and 1.8 GW with ZNEB. Besides fuel cells, CHP enabled micro-turbines also play a role, and the total CHP capacity, considering the building stock growth, can reach 2.5 GW in 2030. This CHP potential in combination with PV and solar thermal reduces the CO_2 emissions by 25% and saves the building owners 11% in total building energy costs. The used commercial building stock roughly represents 37% of the state wide commercial sector electricity consumption. Thus, the 2.5 GW of CHP in 2030 contribute 38% to Governor Brown's research agenda of 6.5 GW of additional CHP in 2030.

The 2.5 GW of CHP in 2030 can only be reached if fuel cell technologies reach very optimistic system efficiencies of 92%, can sustain 20 years without any stack replacement, and if policies are in place that support CO_2 reduction objectives of investors as well as allow for extended payback periods of 10 years.

Finally, the possible CHP potential in 2030 shows a significant variance between 0.2 GW and 2.5 GW and demonstrates the complex interactions between different DER technologies and customer objectives, which underscore the need for integrated optimization/simulation approaches as used by DER-CAM.

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11 Appendix I: Additional information for the 2020 and 2030 results

11.1 2020

11.1.1 All buildings

Table 11-1: 2020 result summary of run sets (4b) and (4d), installed units (source: DER-CAM runs)

run	4a	4b1	4b2	4b3	4b4	4d1	4d2	4d3	4d4
installed units (pieces)	base case	2020 (min US$)	2020 (min US$) + SGIP	2020 (min US$) + high FC efficiency + SGIP	2020 (min US$) + high FC efficiency + 10yrs payback + SGIP	2020 (min CO2)	2020 (min CO2) + SGIP	2020 (min CO2) + high FC efficiency + SGIP	2020 (min CO2) + high FC efficiency + 10yrs payback + SGIP
total number of installed DG units (pieces)	-	9,046	9,357	9,292	16,040	6,726	4,612	5,630	18,966
ICE	-	3,515	3,444	3,131	3,222	183	-	173	840
ICE-HX	-	3,996	4,097	3,414	10,005	3,204	2,781	619	13
GT	-	-	-	-	-	-	-	-	-
GT-HX	-	-	-	-	-	-	-	-	-
MT	-	-	100	-	-	-	-	-	-
MT-HX	-	1,535	1,716	1,616	-	3,307	1,746	1,365	4,468
FC	-	-	-	-	-	-	-	-	991
FC-HX	-	-	-	1,131	2,813	32	85	3,473	12,654
% ICE of DG	-	83.0	80.6	70.4	82.5	50.4	60.3	14.1	4.5
% GT of DG	-	-	-	-	-	-	-	-	-
% MT of DG	-	17.0	19.4	17.4	-	49.2	37.9	24.2	23.6
% FC of DG	-	-	-	12.2	17.5	0.5	1.8	61.7	71.9

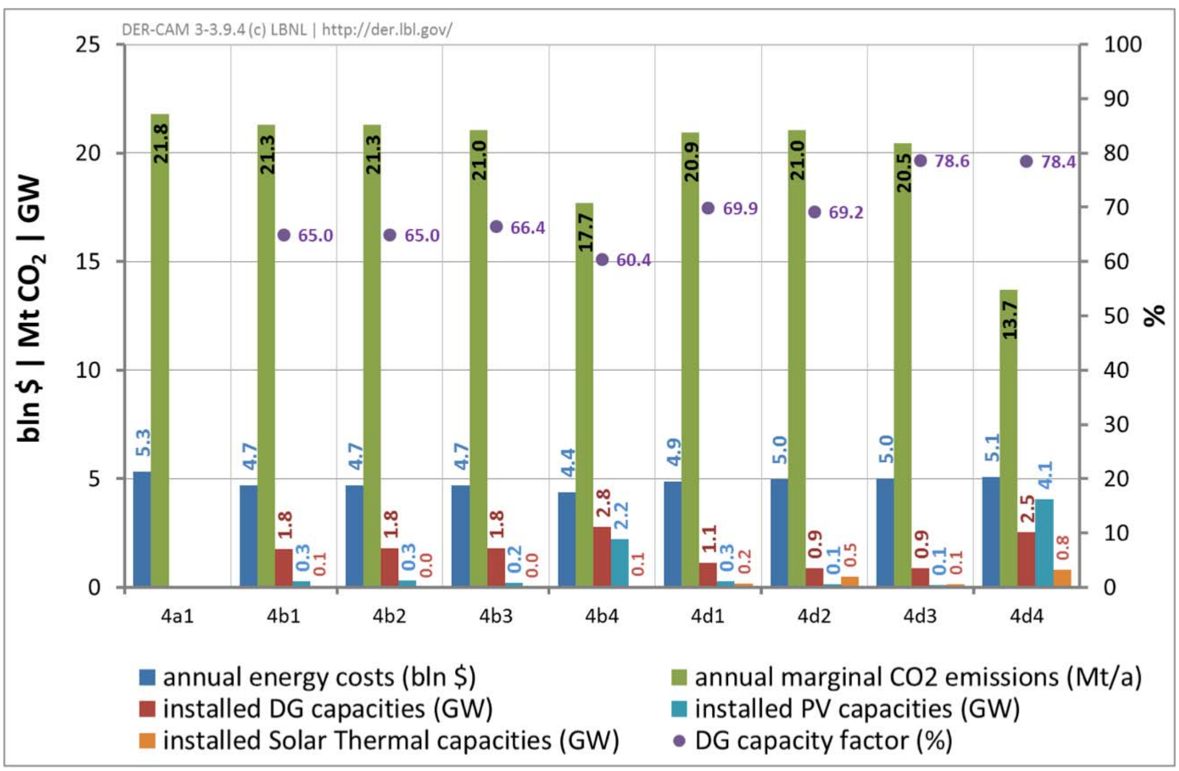

Figure 11-1. 2020 result summary for run sets (4b) and (4d) (source: DER-CAM runs)

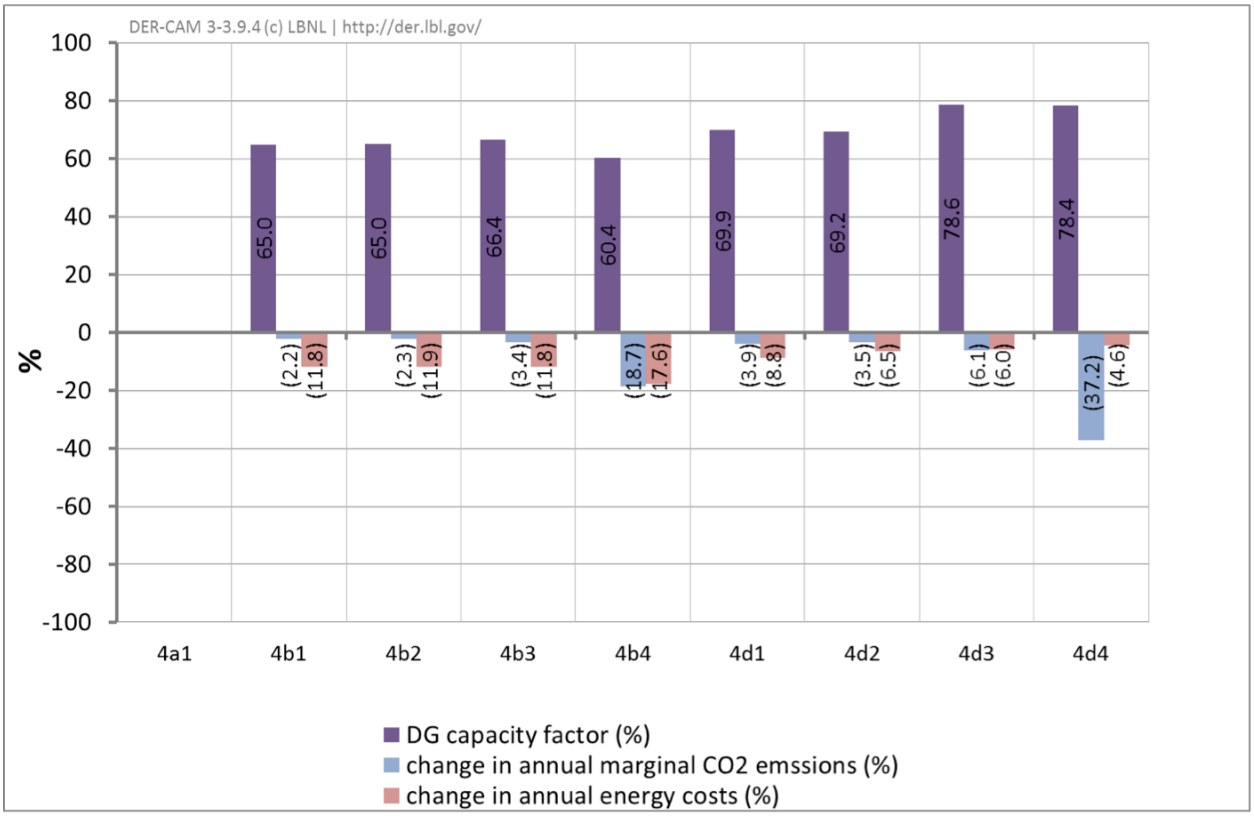

Figure 11-2. 2020 summary for run sets (4b) and (4d) (source: DER-CAM runs)

11.1.2 Restaurants

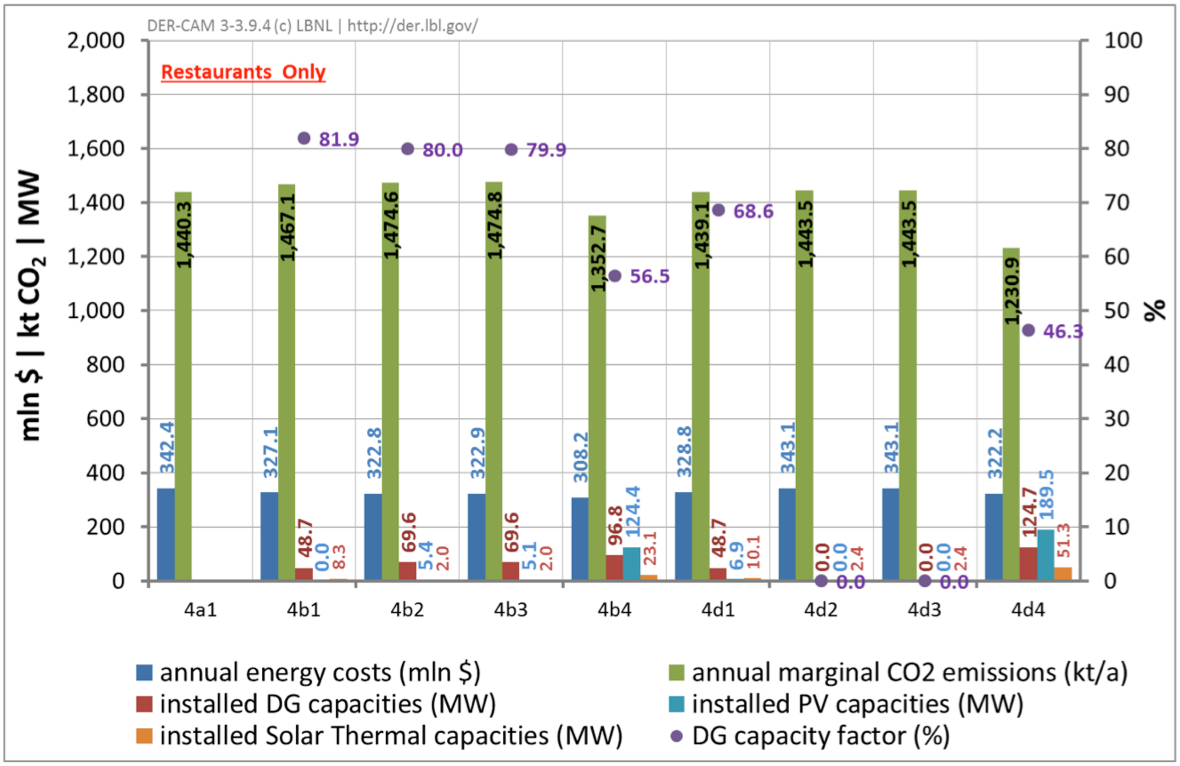

Figure 11-3. 2020 result summary for run sets (4b) and (4d) for the considered restaurants (source: DER-CAM runs)

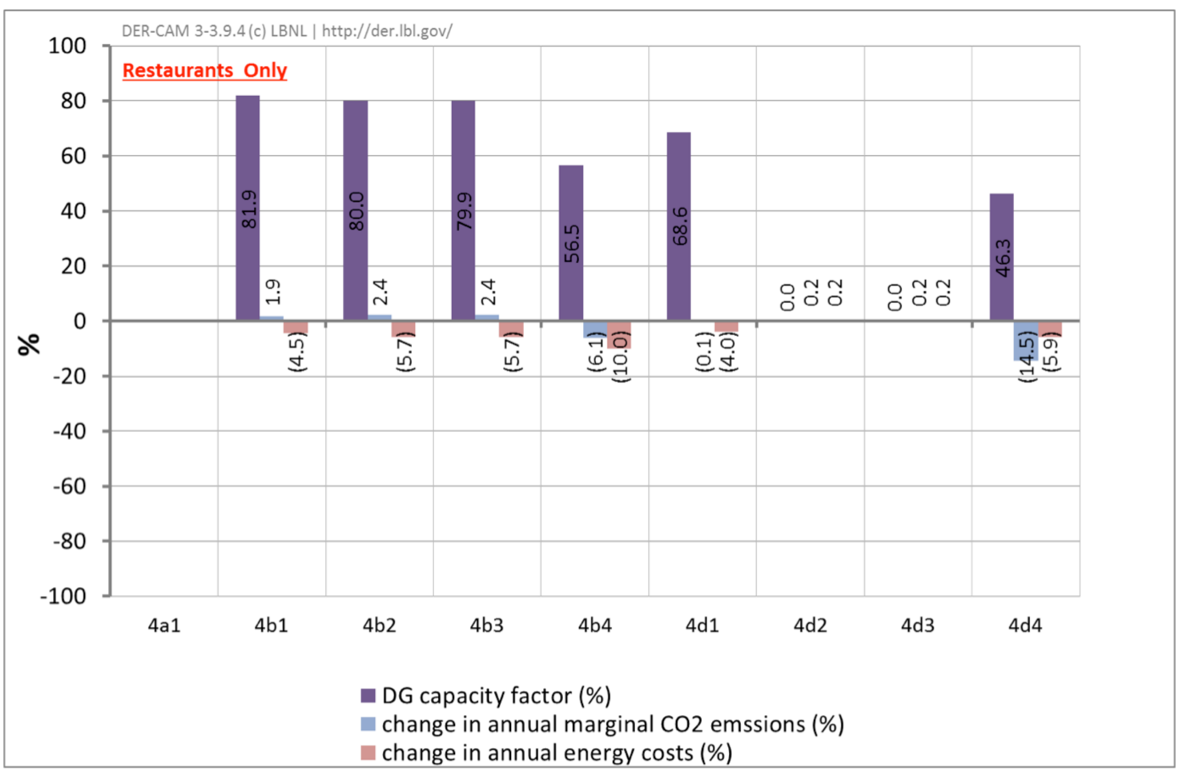

Figure 11-4. 2020 summary for run sets (4b) and (4d) for the considered restaurants (source: DER-CAM runs)

11.2 2030

11.2.1 All buildings

Table 11-2: 2030 result summary of run sets (4a) and (4c), installed units (source: DER-CAM runs)

run	4a2	4a3	4c1	4c2	4c3	4c4	4c5	4c6
installed units (pieces)	2030 base case	2030 base case (2020 CO2 values)	2030 (min US$)	2030 (min US$) + sales	2030 (min US$) + ZNEB	2030 (min US$) + FC20yrs + highFCeta	2030 (min US$) + FC20yrs + lowPV	2030 (min US$) + FC20yrs + highFCeta + 10yrPayback
total number of installed DG units (pieces)	-	-	16,228	18,758	29,810	17,644	16,302	23,561
ICE	-	-	1,153	3,101	27,084	779	1,024	2,308
ICE-HX	-	-	3,698	703	2,096	5,665	3,272	11,539
GT	-	-	-	-	25	-	-	-
GT-HX	-	-	-	-	-	-	-	-
MT	-	-	675	1,227	-	718	196	440
MT-HX	-	-	10,702	13,727	605	10,410	11,810	8,525
FC	-	-	-	-	-	72	-	574
FC-HX	-	-	-	-	-	-	-	175
% ICE of DG	-	-	29.9	20.3	97.9	36.5	26.4	58.8
% GT of DG	-	-	-	-	0.1	-	-	-
% MT of DG	-	-	70.1	79.7	2.0	63.1	73.6	38.1
% FC of DG	-	-	-	-	-	0.4	-	3.2

Table 11-3: 2030 result summary of run sets (4e1)-(4e7), installed units (source: DER-CAM runs)

run	4e1	4e2	4e3	4e4	4e5	4e6	4e7
installed units (pieces)	2030 (min CO2)	2030 (min CO2) + sales	2030 (minCO2) + FC20yrs	2030 (minCO2) + FC20yrs + w/o FC constraint	2030 (minCO2) + FC20yrs + ZNEB	2030 (minCO2) + FC20yrs + ZNEB + w/o FC constraint	2030 (minCO2) + FC20yrs + highFCeta
total number of installed DG units (pieces)	10,045	11,526	9,841	9,503	3,006	2,955	11,098
ICE	-	-	-	-	-	-	-
ICE-HX	-	-	-	-	-	-	-
GT	-	-	-	-	-	-	-
GT-HX	-	-	-	-	-	-	-
MT	-	-	-	-	51	-	-
MT-HX	9,890	11,384	9,686	9,348	2,955	2,955	9,112
FC	-	-	-	-	-	-	235
FC-HX	155	142	155	155	-	-	1,751
% ICE of DG	-	-	-	-	-	-	-
% GT of DG	-	-	-	-	-	-	-
% MT of DG	98.5	98.8	98.4	98.4	100.0	100.0	82.1
% FC of DG	1.5	1.2	1.6	1.6	-	-	17.9

Table 11-4: 2030 result summary of run sets (4e8)-(4e14), installed units (source: DER-CAM runs)

run	4e8	4e9	4e10	4e11	4e12	4e13	4e14
installed units (pieces)	2030 (minCO2) + FC20yrs + highFCeta + 2020gridCO2	2030 (minCO2) + FC20yrs + lowPV	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback + lowPV + sales	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback + lowPV + ZNEB	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback + smaller FC	2030 (minCO2) + FC20yrs + highFCeta + 10yrPayback + small DG
total number of installed DG units (pieces)	17,536	10,318	20,242	17,590	15,663	26,004	58,160
ICE	-	-	334	-	-	456	1,897
ICE-HX	-	-	-	173	235	-	-
GT	-	-	-	-	-	-	-
GT-HX	-	-	-	-	-	-	-
MT	4	-	6	286	6	-	-
MT-HX	14,876	10,150	12,665	6,728	6,826	12,169	26,035
FC	699	-	212	364	14	536	633
FC-HX	1,957	168	7,025	10,039	8,582	12,843	29,594
% ICE of DG	-	-	1.7	1.0	1.5	1.8	3.3
% GT of DG	-	-	-	-	-	-	-
% MT of DG	84.9	98.4	62.6	39.9	43.6	46.8	44.8
% FC of DG	15.1	1.6	35.8	59.1	54.9	51.4	52.0

Please compare run set (4e10) with run set (4e14) in terms of adopted units. Run set (4e14) uses smaller unit sizes and this greatly impacts the total number of units installed, but not the total installed capacity. Please check also Table 5-8.

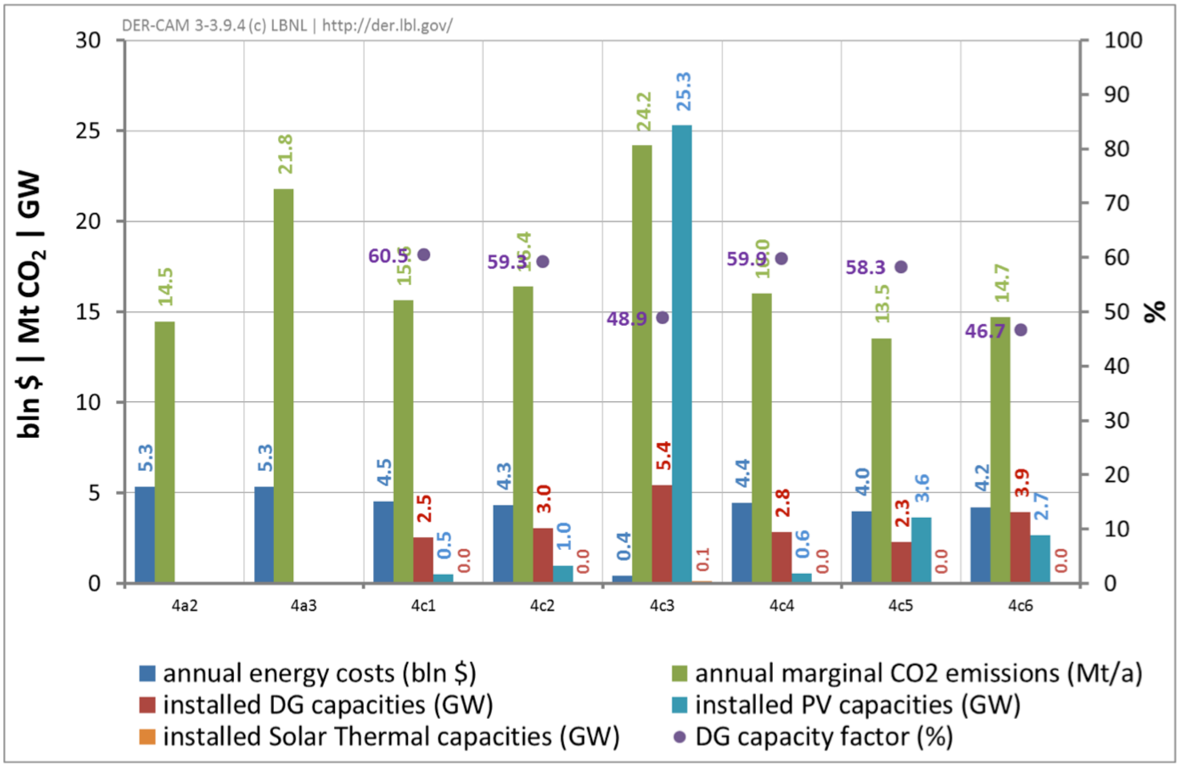

Figure 11-5. 2030 result summary for run sets (4a) and (4c) (source: DER-CAM runs)

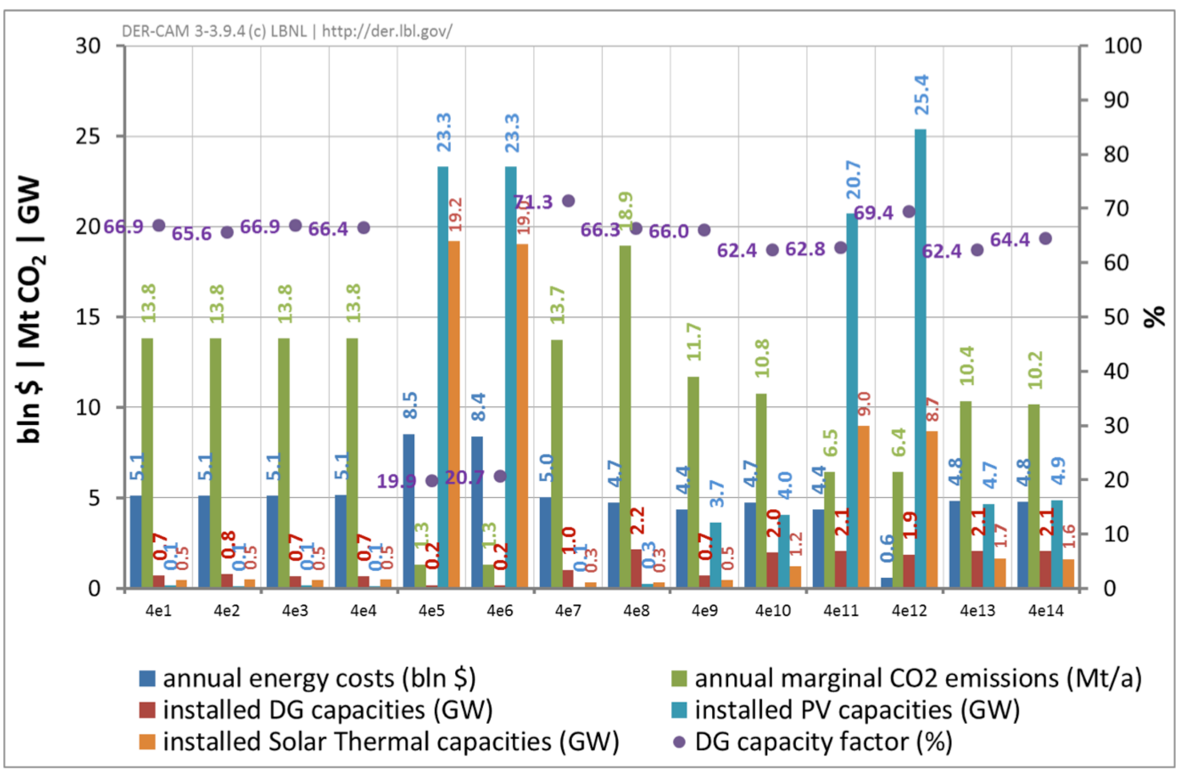

Figure 11-6. 2030 result summary for run sets (4e) (source: DER-CAM runs)

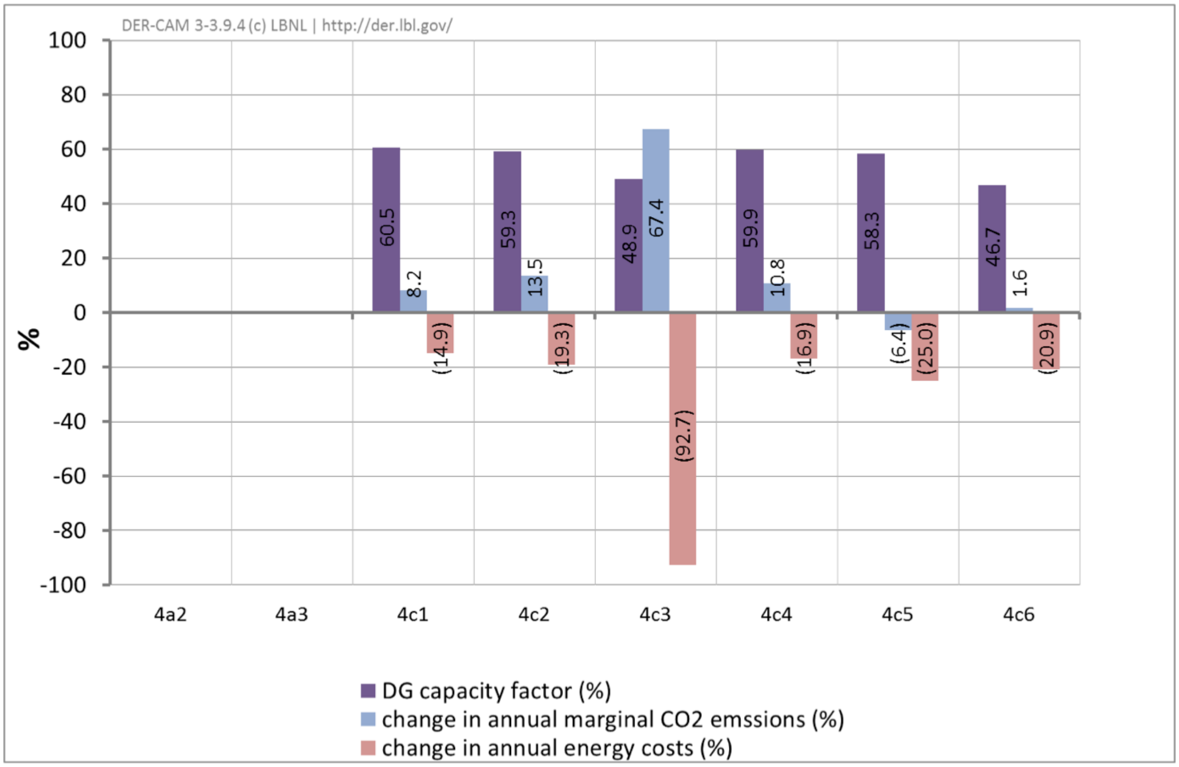

Figure 11-7. 2030 summary for run sets (4a) and (4c) (source: DER-CAM runs)

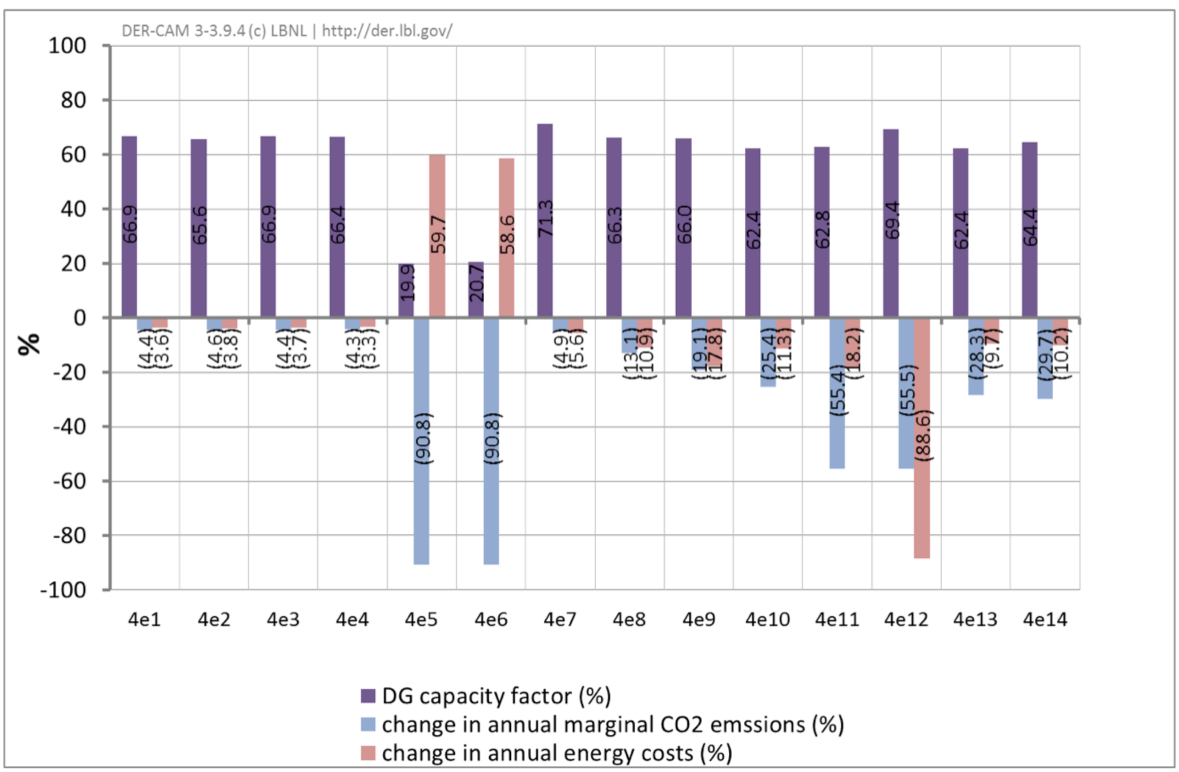

Figure 11-8. 2030 summary for run sets (4e) (source: DER-CAM runs)

11.2.2 Restaurants

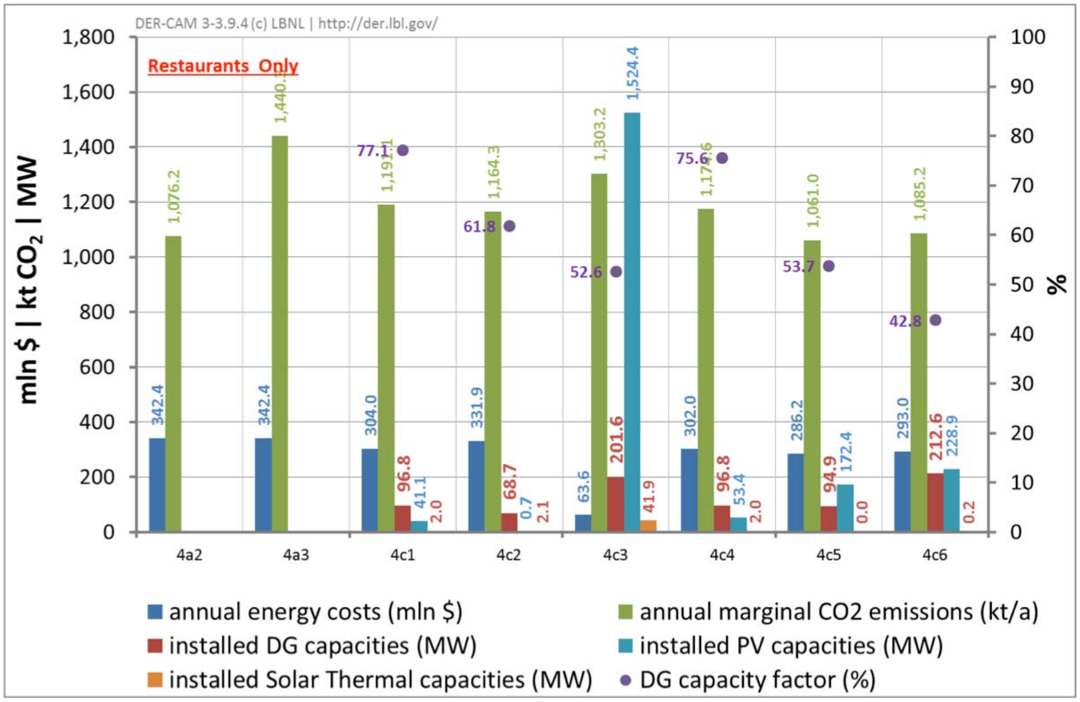

Figure 11-9. 2030 result summary for run sets (4a) and (4c) for the considered restaurants (source: DER-CAM runs)

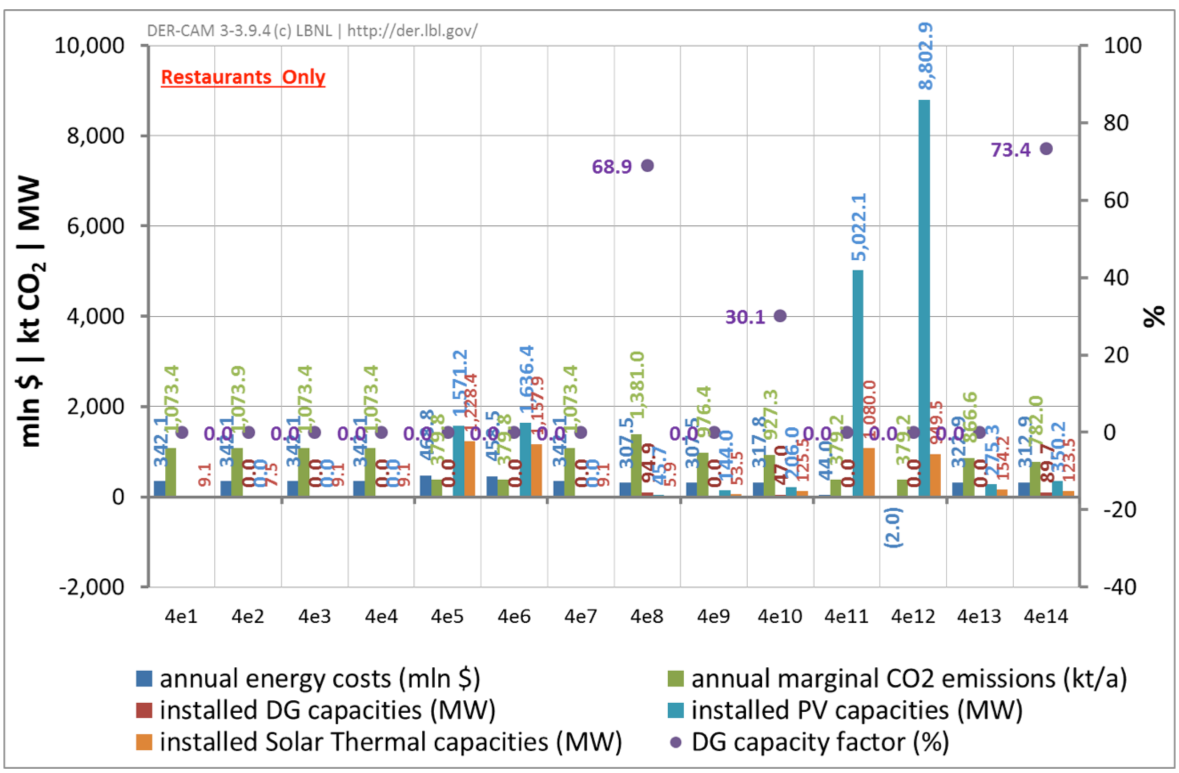

Figure 11-10. 2030 result summary for run sets (4e) for the considered restaurants (source: DER-CAM runs)

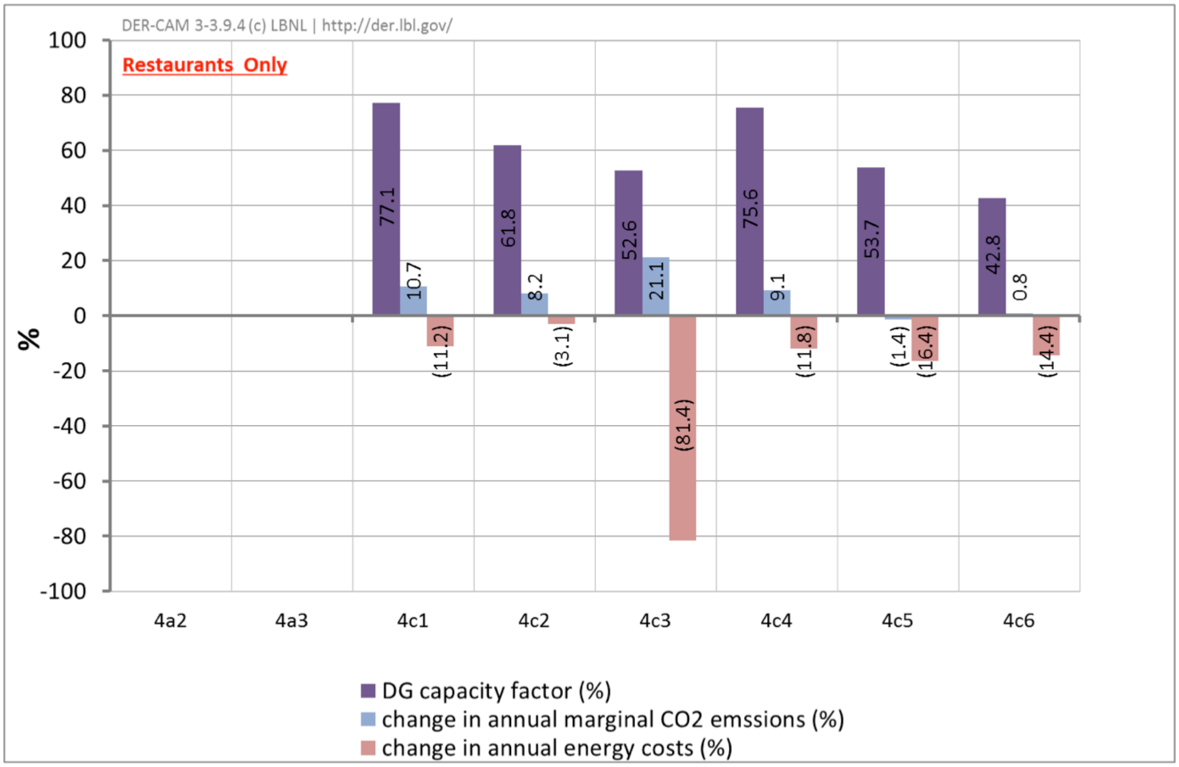

Figure 11-11. 2030 summary for run sets (4a) and (4c) for the considered restaurants (source: DER-CAM runs)

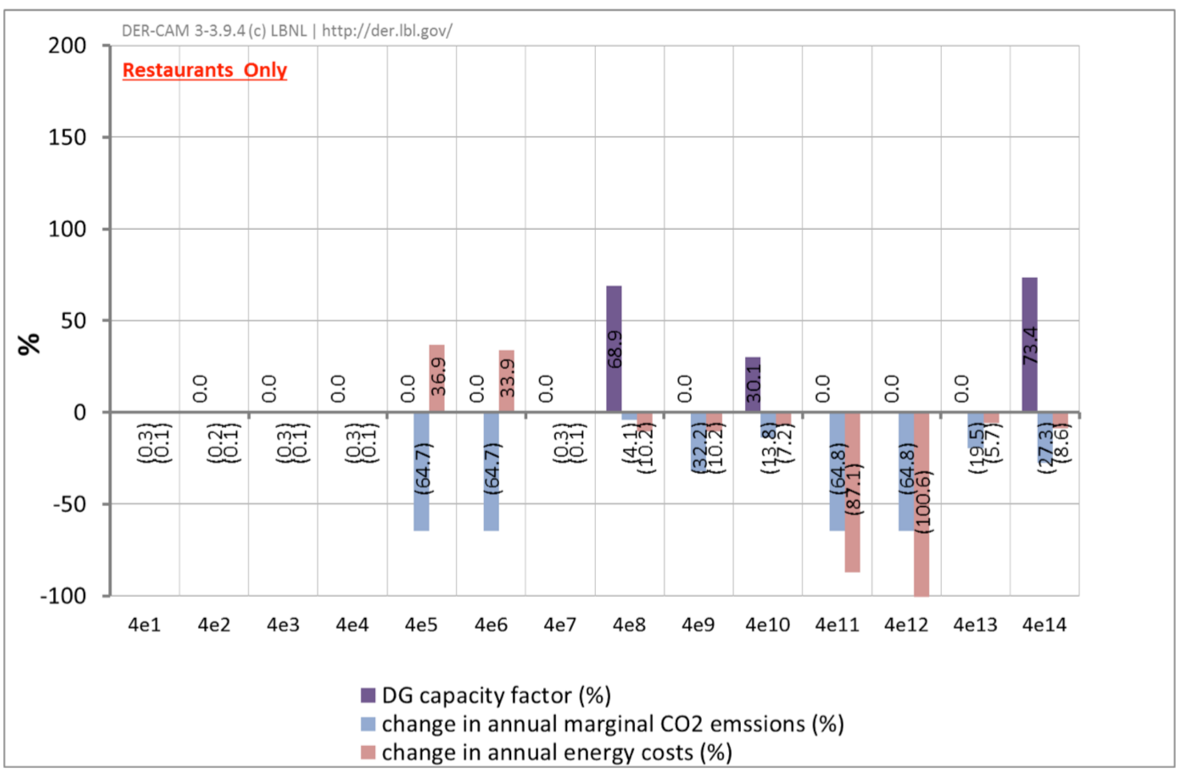

Figure 11-12. 2030 summary for run sets (4e) for the considered restaurants (source: DER-CAM runs)

12 Appendix II: Collected Data Memorandum

Collected Data Memorandum for task 2.8

Encouraging Combined Heat and Power in California Buildings

CEC 500-10-052, task 2.8

Principal Investigator: Michael Stadler
Energy Commission Project Manager: Golam Kibrya
LBNL Project Team: Michael Stadler, Chris Marnay, Judy Lai, Andreas Müller,
Gonçalo Cardoso, Nicholas DeForest

12.1 Background

The goal of task 2.8 is to stimulate economic and environmentally sound natural gas-fired combined heat and power (CHP) and combined cooling, heating, and electric power (CCHP) adoption in California's medium sized commercial building sector.

This analysis will not be done in isolation and will consider other distributed energy resources (DER) technologies such as PV, solar thermal, electric and heat storage, which can be in competition with CHP and CCHP or supplement each other, depending on the building type and DER adoption strategy.

For this analysis the Distributed Energy Resources Customer Adoption Model (DER-CAM) from Lawrence Berkeley National Laboratory will be used. DER-CAM is a mixed-integer linear program (MILP) written and executed in the General Algebraic Modeling System (GAMS) (Stadler et al., 2010). Its objective is typically to minimize the annual costs or CO_2 emissions for providing energy services to the modeled site/building, including utility electricity and natural gas purchases, plus amortized capital and maintenance costs for any distributed generation (DG) investments. Other objectives, such as carbon or energy minimization, or a combination are also possible. The approach is fully technology-neutral and can include energy purchases, on-site conversion, both electrical and thermal on-site renewable harvesting, and end-use efficiency investments. Furthermore, this approach considers the simultaneity of results. For example, building cooling technology is chosen such that results reflect the benefit of electricity demand displacement by heat-activated cooling, which lowers building peak load and, therefore, the on-site generation requirement, and also has a disproportionate benefit on bills because of demand charges and time-of-use energy charges. Site-specific inputs to the model are end-use energy loads, detailed electricity and natural gas tariffs, and DER investment options. Figure 1 shows a high-level schematic of the building energy flows modeled in DER-CAM. Available energy inputs to the site are solar radiation, utility electricity, utility natural gas, biofuels, and geothermal heat. For a given site, DER-CAM selects the economically or environmental optimal combination of utility electricity purchase, on-site generation, storage and cooling equipment required to meet the site's end-use loads at each time step.

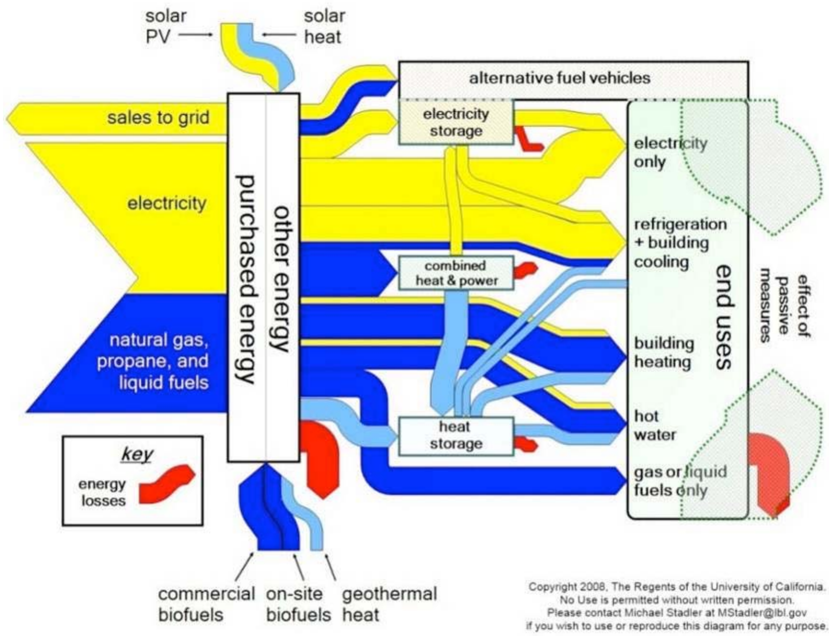

Figure 12-1. Schematic of energy flows in DER-CAM (Stadler et al., 2010)

The outputs of DER-CAM include the optimal DER/storage adoption and an hourly operating schedule for a specified year, as well as the resulting costs, fuel consumption, and CO_2 emissions. The approach does not consider CHP in isolation, but rather picks optimal DER equipment combinations and their operations of typical buildings (roughly 150) in the California commercial end-use survey database (CEUS) data base (CEUS, 2006) and aggregates them to statewide results.

12.2 Aspects considered in this project

Berkeley lab will

- perform optimization runs for 2030 and update existing 2020 runs (Stadler et al., 2010)
- develop multiple scenarios that reflect grid decarburization, changes in equipment performance, and regulatory environment; besides CO_2 emissions also NOx emissions will be considered in the DER-CAM runs
- consider zero net energy buildings and their impact on CHP and CCHP
- consider different feed-in tariffs
- consider the impact of CO_2 pricing (e.g. cap and trade) on CHP/CCHP adoption
- put a special focus on the California restaurant sector since it is a major consumer of natural gas.

12.3 Data needed for the DER-CAM runs

To perform the described analysis with DER-CAM following data will be needed:

- **hourly** electricity, heating, cooling, domestic hot water, and cooking demand for the selected representative commercial buildings; the buildings will be selected from CEUS.
- electric and natural gas tariffs
- technology performance data and costs for the selected DER technologies
- CO_2 emissions of the macro-grid to assess the CO_2 mitigate potential of CHP and CCHP and other DER

- solar radiation for different locations in California to be able to consider the impact of PV and solar thermal on CHP/CCHP adoption.

12.4 Objective of this memorandum

Description of the most important data collected for the DER-CAM runs.

Please note that all data described in this memorandum are subject to updates/changes in course of the project. Task 2.8 started on Jan 1 2012 and the “Collected Data Memorandum” is the first deliverable within this task.

12.5 Collected data

12.5.1 CEUS building data

The CEUS dataset contains 2790 premises from 4 local service entities in California and representative buildings will be picked from CEUS. The representative buildings will most likely range between 100kW and 5MW electric peak loads. Restaurants will be analyzed in more detail, and therefore, smaller electric peak loads will be considered for restaurants.

Energy data collected in CEUS:

- PG&E: 1001 premises
- SMUD: 300 premises
- SCE: 1144 premises
- SDG&E: 345 premises

The 2790 premises are subdivided into

- 12 building types, 3+1 sizes for each building type as small (S), medium (M), large (L), and Census
- 13 end-uses (3 HVAC, 10 Non-HVAC); the samples contain simulated hourly estimates of end-use consumption as of electricity and natural gas alone, i.e. no propane
- 15 total Forecasting Climate Zones (FZ); using 10 year normalized weather, and the
- data is based on eQUEST simulations.

The 12 commercial building types considered in CEUS and corresponding main data are displayed in Table 12-1.

Table 12-1. Building types distinguished by the CEUS database (source: CEUS and CEUS, 2006)

building type	total sample frame (#)	total energy consumption (GWh/a)	floor stock (MSqFt)	total electricity consumption (GWh/a)	total gas consumption (10,000 therms/a)
Small Office (<30 000 sqft)	216981	5855	362	4738	3810
Large Office (>30 000 sqft)	4235	15935	660	11691	14482
Restaurant	50697	15149	149	5986	31264
Retail	86863	10823	702	9871	3246
Food/Liquor	26510	7078	144	5911	3981
Unrefrigerated Warehouse	40596	2966	554	2467	1702
Refrigerated Warehouse	1706	2069	96	1913	535
School	13577	5388	445	3322	7107
College	3664	4607	206	2524	7051
Health Care	7305	9710	233	4561	17569
Hotel/Motel	7337	6631	270	3275	11451
Miscellaneous	148145	18337	1100	10817	25659

In the data collection process of the CEUS project, these 12 buildings types were split up into sub categories. E.g. the sector “Restaurant” was subdivided into the five categories:

- Fast Food or Self Service
- Specialty/Novelty Food Service
- Table Service
- Bar/Tavern/Nightclub/Other
- Other Food Service.

However, data on this sublevel are not published, and therefore, not accessible. This is a major limitation for the restaurant specific analysis and needs to be addressed. A solution would be to request more detailed data on the restaurant sector from ITRON.

Besides Census buildings[10], each building type is subdivided into three different sizes classes. This has been done based on the annual electricity consumption.

Table 12-2. Building-Type size strata cut-points used in the CEUS project (source: CEUS, 2006)

Building Type	Cutpoints (Annual kWh)		
	Small	Medium	Large
1. Small Office	< 15,000	15,000 to 100,000	>= 100,000[3]
2. Large Office	< 2,000,000	2,000,000 to 4,750,000	>= 4,750,000
3. Restaurant	< 90,000	90,000 to 315,000	>= 315,000
4. Retail Store	< 80,000	80,000 to 900,000	>= 900,000
5. Food/Liquor	< 190,000	190,000 to 1,600,000	>= 1,600,000
6. Unrefrigerated Warehouse	< 85,000	85,000 to 1,000,000	>= 1,000,000
7. School	< 250,000	250,000 to 1,000,000	>= 1,000,000
8. College	< 400,000	400,000 to 3,750,000	>= 3,750,000
9. Health Care	< 450,000	450,000 to 3,000,000	>= 3,000,000
10. Hotel	< 300,000	300,000 to 2,200,000	>= 2,200,000
11. Misc	< 30,000	30,000 to 500,000	>= 500,000
25. Refrigerated Warehouse	< 500,000	500,000 to 3,000,000	>= 3,000,000

Based on the classification shown above, the following sample frame numbers have been derived.

[10] The Census strata consist of all premises with annual GWh consumption above 12.9, or 0.02% of the total annual GWh for the three IOUs combined.

Table 12-3. Sample frame numbers per building type and size (source: CEUS, 2006)

	sample frame (#)			
	1. small	2. medium	3. large	4. census
Small Office (<30 000 sqft)	122755	75223	19003	
Large Office (>30 000 sqft)	2760	992	409	74
Restaurant	31502	15231	3964	
Retail	70360	14606	1883	14
Food/Liquor	20668	4396	1437	9
Unrefrigerated Warehouse	33756	6182	649	9
Refrigerated Warehouse	1391	248	62	5
School	9296	3587	694	
College	3259	292	88	25
Health Care	6046	990	212	57
Hotel/Motel	5775	1311	237	14
Miscellaneous	107439	38213	2445	48

On the level of sizes classes (large, medium, small), CEUS provides the total annual electricity consumption only.

Specific data on the gas consumption are not available on this level of disaggregation.

12.5.1.1 Forecasting Climate Zones (FZs) and utilities

The CEUS project divided California into 15 climate and utility territories. LADWP as well as FZ 14 and 15 are not covered by CEUS. This project will consider the most important climate zones and utilities in terms of population density and pick representative commercial buildings in the different climate zones. In the 100kW to 5MW electric peak load range roughly 150 are considered at this point. This number is likely to change in course of the project.

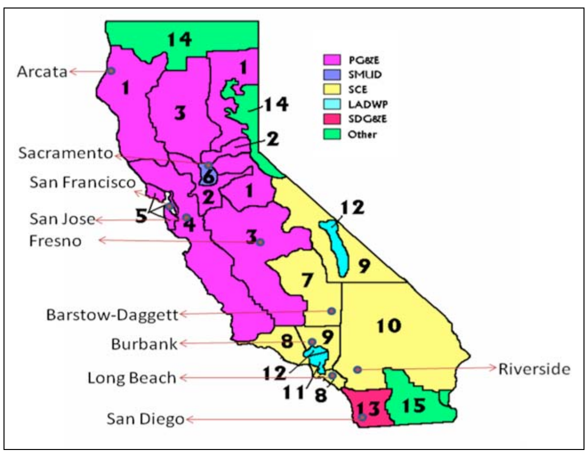

Figure 12-2. Forecasting climate zones and utility territories (source: based on CEUS, 2012)

12.5.1.2 Energy demand per end-uses

Figure 12-3 depicts the annual energy consumption by end-uses and energy carrier of the building types described in CEUS and shows that most of the natural gas use in the restaurant sector is used for cooking. This observation will make it challenging to use CHP/CCHP in the restaurant sector since basically only 2000GWh of the approx. 9000GWh could be substituted by waste heat. On the other hand, comparing the hot water needs in the restaurant sector with the hotel hot water needs, and knowing that hotels are very attractive hosts for CHP/CCHP, increases the potential for CHP/CCHP (Stadler et al., 2010).

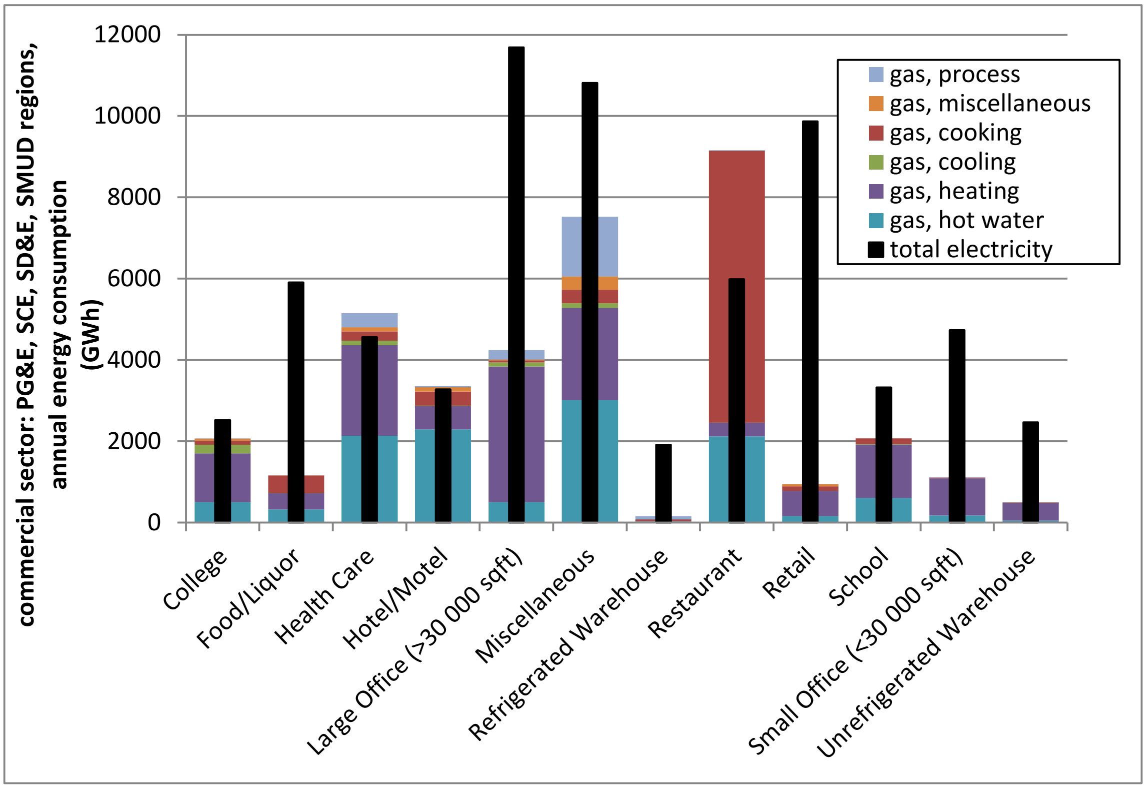

Figure 12-3. Annual energy consumption of building types descripted by the CEUS project (source: CEUS, 2012)

12.5.2 Restaurants

Since restaurants play an important role in this project a closer look to the restaurant sector is given in this section.

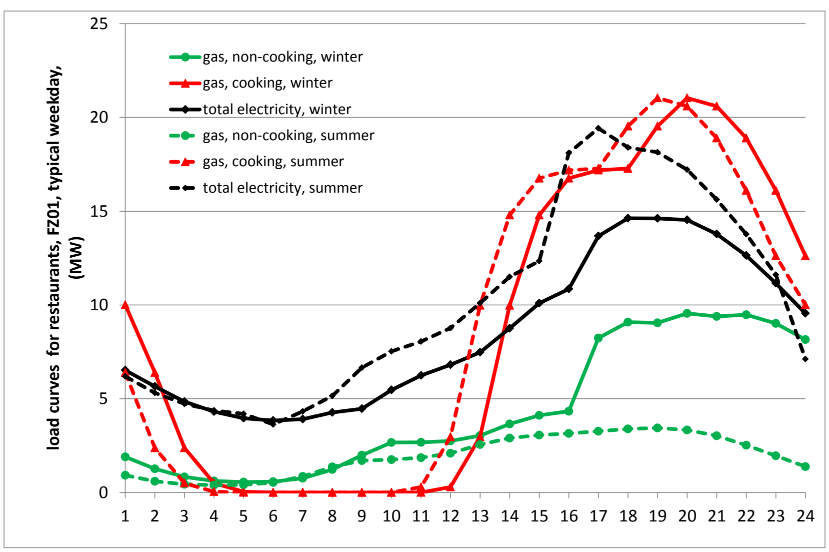

Figure 12-4. Average load profile of all restaurants in the FZ01 zone for an average summer and winter day (Source: CEUS, 2012)

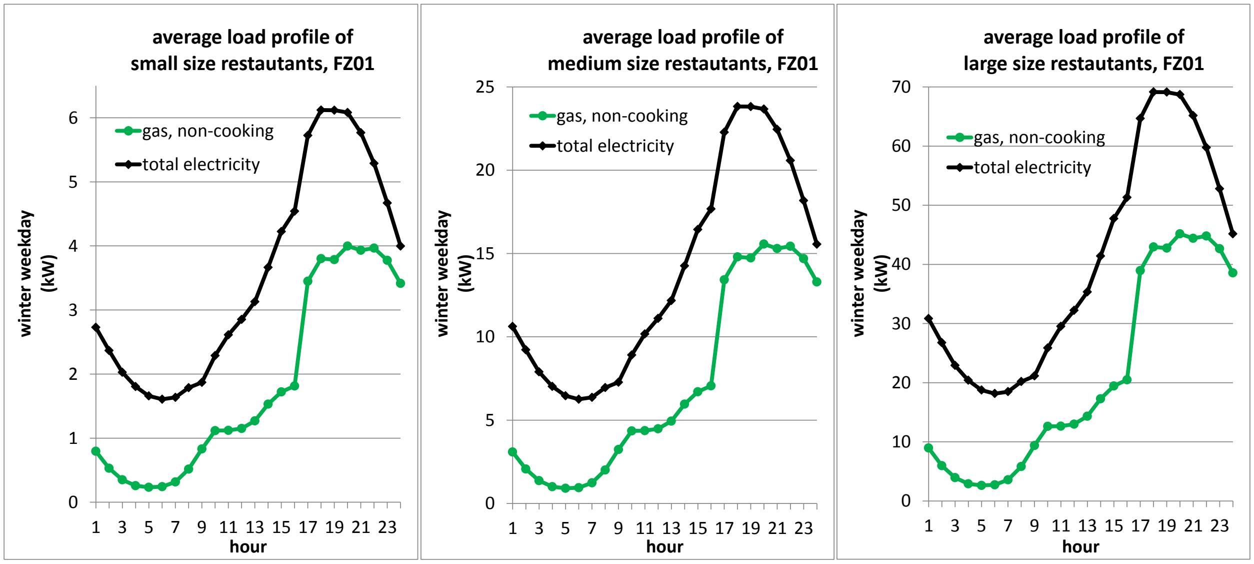

Figure 12-5. Average load profiles for restaurants with different sizes in the FZ01 region (source: CEUS, CEUS, 2006, and own calculations)

As can be seen from Figure 12-5 all three different restaurant sizes have the same load profile shape and are only scaled to meet "small", "medium", and "large" definitions of the CEUS database. The public available restaurant data does not contain *detailed* load shape information for the different sizes and this might create a problem during the DER-CAM runs and limit the restaurant analysis. To avoid such problems a release of the detailed restaurant load profile data by ITRON would help.

However, more specific data for the food service sector, available from the U.S. Census Bureau (Economic Census, 2005) are shown in Table 12-4.

Table 12-4. Food sector in California 2002 (source: Economic Census, 2005)

						operated by a franchisor or franchisee		
		establish-ments (tds.)	sales (Mio. $)	seats (thousand)	employees (thousand)	establish-ments	sales (Mio. $)	employees (thousand)
full service restaurants		**23.3**	**18580**	**1692**	**441**	**1.7**	**2005**	**53.5**
limited service restaurants	**all establishments**	**23.5**	**15661**	**1115**	**358**	**9.7**	**8417**	**203.4**
	order and pay at counter with inside seating	14.2	7828	1115				
	take out/drive through	7.2	6635					
	delivery	1.0	624					
	Cafeteria line with inside seating	0.4	155					
	other	0.8	419					
Cafeterias, buffets, and grill buffets		**0.7**	**665**	**78**				

12.5.2.1 Applicability of energy efficiency measures

To obtain a better picture about the applicability of DER and CHP, which is in competition with "regular" efficiency measures, some basic data on energy efficiency measures was collected.

Estimates for the applicability (including feasibility factor, technical potential, economic potential as well as maximum, current and natural achievements) of different energy saving and peak load reduction measures focusing on the natural gas consumption in the California commercial sector and their related costs are given by Dickerson et al., 2003. Measures that could reduce the gas consumption in the restaurant sector and their potential are shown in Table 12-5. The data shown exemplary for the restaurants in Table 12-5 and Table 12-6 are also available for the other commercial sectors defined by CEUS.

Table 12-5. Overview natural gas saving measures in the restaurant sector (source: Dickerson et al., 2003)

	Measure Description	Energy Savings	Peak Reduction	Feasibility Factor	Incomplete Factor	Technology Saturation (units/ft²) **)	Total Costs/$	Non-Additive Technical Potential (tds. Therms) PG&E	SCG	SDG&E
Heating	Ceiling Insulation (In situ R5 to R24)	5%	5%	50%	22%	0.96 / 0.95	0.47	33	32	8
Heating	Double Pane Low Emissivity	4%	4%	50%	100%	0.05 / 0.05	0.03	62	96	21
Heating	Duct Leakage Repair	2%		50%	25%	1 / 1				
Heating	High Efficiency Furnace/Boiler 95% Eff	18%	18%	90%	95%	0.04 / 0.03	0.22	669	783	196
Heating	Boiler- Heating Pipe Insulation	2%	2%	50%	25%	0.08 / 0.08	0.31	0	0	0
Heating	Boiler Tune-Up	2%	2%	100%	25%	0 / 0	0.03	0	1	0
Heating	EMS install	10%	10%	75%	95%	1 / 1	0.29	316	387	75
Heating	EMS Optimization	1%	1%	90%	75%	0 / 0	0.11	30	35	9
Heating	Stack Heat Exchanger	5%		50%	86%	0 / 0				
Heating	Heat Recovery from Air to Air	25%	25%	50%	100%	1 / 1	2.00	554	648	162
Heating	Heat Recovery from AC	63%		10%	86%	1 / 1				
Water Heating	**Eff Gas Water Heater System 95% Eff**	**25%**	**25%**	**95%**	**54%**	**0.02 / 0.03**	**0.35**	**3843**	**9334**	**2332**
Water Heating	Instantaneous Water Heater <=200 MBTUH	10%	10%	10%	97%	0.02 / 0.03	0.12	256	593	148
Water Heating	Circulation Pump Timeclocks	3%	3%	10%	100%	0 / 0	0.04	86	210	52
Water Heating	Tank Insulation	5%	5%	95%	50%	0 / 0	0.04	701	1703	426
Water Heating	Pipe Insulation	2%	2%	50%	75%	0.01 / 0.01	0.03	216	578	144
Water Heating	Faucet Aerator	2%	2%	25%	50%	0 / 0	0.01	73	177	44
Water Heating	**Solar DHW System Active**	**60%**	**60%**	**30%**	**100%**	**0.03 / 0.03**	**1.72**	**5182**	**12585**	**3145**
Cooking	**Efficient Infrared Griddle**	**7%**	**7%**	**100%**	**95%**	**0.06 / 0.12**	**0.91**	**5172**	**14466**	**3615**
Cooking	**Convection Oven**	**6%**	**6%**	**100%**	**85%**	**0.06 / 0.12**	**3.18**	**3989**	**11156**	**2787**
Cooking	**Infrared Conveyer Oven**	**15%**	**15%**	**100%**	**95%**	**0.06 / 0.12**	**4.15**	**11128**	**31124**	**7777**
Cooking	**Infrared Fryer**	**15%**	**15%**	**100%**	**95%**	**0.06 / 0.12**	**1.30**	**11128**	**31124**	**7777**
Cooking	**Power Burner Oven**	**4%**	**4%**	**100%**	**95%**	**0.06 / 0.12**	**3.87**	**3142**	**8787**	**2196**
Cooking	**Power Burner Fryer**	**4%**	**4%**	**100%**	**95%**	**0.06 / 0.12**	**1.55**	**3142**	**8787**	**2196**

**)PG&E / SCG, SDG&E

As shown above, restaurants consume most of the natural gas in the commercial sector, but the sector is also very fragmented and a lot of small restaurants exist, creating barriers for CHP/CCHP adoption. Only one restaurant sample of the CEUS database is above 100kW electric peak load (see Figure 12-6).

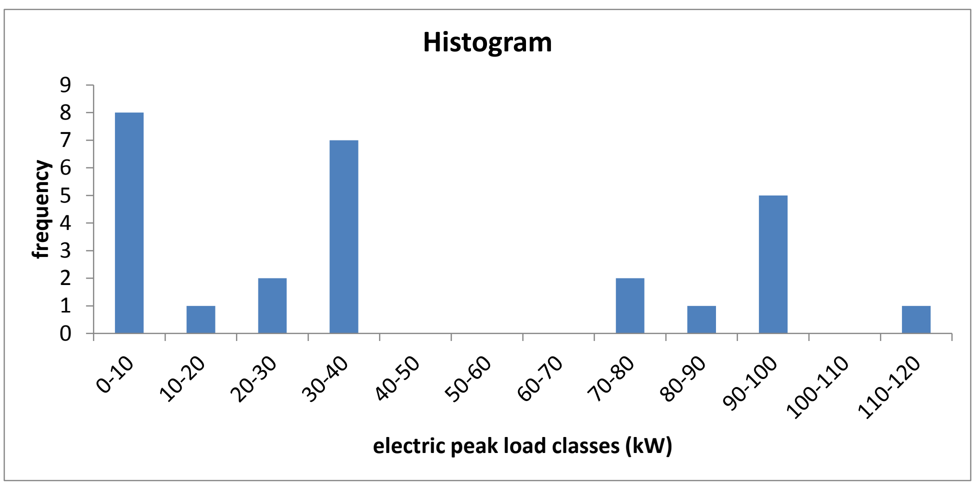

Figure 12-6. Size distribution of restaurant samples based on the electric peak load (source: CEUS, 2006)

In other words, the adoption patterns from DER-CAM, which are based on economic decisions, need to be evaluated within this project. This could be done by obtaining more information on the load profiles from CEUS. However, since the public available CEUS data regarding restaurants is very limited it is necessary to find other indicators, which allow estimating the real CHP/CCHP potential in the restaurant sector. For example, the "feasibility factor" of 30% for "Solar DHW System Active" from Table 12-5 might be a good indicator for CHP/CCHP feasibility since similar technical aspects and problems apply to CHP/CCHP adoption.

Table 12-6. Natural gas saving potentials in the restaurant sector (source: Dickerson et al., 2003)

Utility	End Use	Total Natural Gas Consumption (Mtherms)	Energy Saving Potential						
			Technical	Economic	Max Ach	100% Ach	50% Ach	Curr Ach	Nat Occur
PG&E	Heating	4.3	33.8%						
	Water Heating	28.1	33.0%	17.7%	8.1%	4.9%	3.3%	1.9%	0.3%
	Cooking	75.6	41.3%	20.6%	6.4%	2.9%	1.8%	0.8%	0.1%
SCG / SDG&E	Heating	6.3	34.0%						
	Water Heating	85.2	33.0%	33.0%	22.1%	6.2%	4.3%	2.5%	0.3%
	Cooking	264.2	41.3%	20.6%	6.4%	2.9%	1.8%	0.8%	0.1%

The estimated energy saving potential shown in Table 12-6 considers different forms of barriers. While the technical potential are calculated on data shown in Table 12-5 and the economic potentials consider the economic framework conditions described in the Appendix B ECONOMIC INPUTS (Dickerson et al., 2003). For the achievable (Ach) potential, a market adoption model has been applied.

For more information on energy efficiency potentials in California see Shelton and Harcharik, 2006.

12.6 Electric and natural gas tariffs

Since electric and natural gas tariffs and their spread have a major influence on DER and CHP/CCHP adoption a special focus has to be put on them.

This section of the memo describes the "general" commercial electricity tariffs for customers in the Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) territories of California. Tariffs that are closed to new customers, that are applicable only to specialized customers and/or are voluntary are shown and briefly described in Table 12-22. The tariffs are presented in summary tables and the energy charges ($/kWh) are inclusive of CPUC-approved fees, surcharges, etc. We also assume that the sites take delivery at either secondary or primary voltages (below 2 kV or over 2kV unless otherwise noted).

12.6.1 San Diego Gas and Electric

A summary of available SDG&E electricity tariffs is shown in Table 12-7.

A customer uses schedule A-1 if its max demand is 20 kW or less; AL-TOU if its max demand is between 20 kW and 500 kW, and A6-TOU if its max demand is over 500 kW. Customers with demand above 20 kW can optionally participate in SDG&E's Capacity Bidding Program (CBP), and those with distributed generation equipment installed may elect to be placed on the DG-R tariff. For customers within the city of San Diego, there is a franchise fee differential of 5.78% for electricity service (total bill increases by 5.78% to cover the higher costs within San Diego).

Table 12-7. Available SDG&E electricity tariffs (SDG&E, 2012a)

schedule	max demand	time and facility demand charge
A-1	up to 20 kW	no
AL-TOU	between 20 and 500 kW	yes
A6-TOU	500 kW +	yes

12.6.1.1 Example electricity schedules in detail

Table 12-8. SDG&E electricity tariff for customers loads between 20 and 500 kW (eff. Jan 1 2012, source: SDG&E, 2012a)

		summer (May - Sep)			winter (Nov - Apr)		
		on peak	mid peak	off peak	on peak	mid peak	off peak
electricity (AL-TOU) secondary	**fixed ($/month)**	$					58.22
	energy ($/kWh)	$ 0.10442	$0.08514	$ 0.06477	0.09855	0.09026	0.0701
	demand charge (per kW)	$ 11.18			$ 4.54		
	non-coincident demand charge ($/kW month	$ 13.63	$ 13.63	$ 13.63	$ 13.63	$ 13.63	$ 13.63

Table 12-9. SDG&E electricity tariff for customers loads above 500 kW (eff. Jan 1 2012, source: SDG&E, 2012a)

		summer (May - Sep)			winter (Nov - Apr)		
		on peak	mid peak	off peak	on peak	mid peak	off peak
electricity (A6-TOU) primary	**fixed ($/month)**	$					232.87
	energy ($/kWh)	$0.10015	$0.08235	$0.06245	$0.09491	$0.08737	$ 0.06767
	demand charge (per kW)	$ 15.54			$ 5.46		
	non-coincident demand charge ($/kW month	$ 13.32	$ 13.32	$ 13.32	$ 13.32	$ 13.32	$ 13.32

12.6.1.2 Natural gas schedules

The gas rate is separated into three tiers depending on usage (0 to 1000 therms/mo; 1001 to 21,000 therms/mo, and over 21,000 therms/mo). For representation purposes, the therms have been converted to kWh and the three tiers averaged. For customers within the city of San Diego, there is a franchise fee differential of 1.03% for natural gas delivery (total bill increases by 1.03% to cover the higher costs within San Diego).

Table 12-10. SDG&E gas tariff (eff. Jan 10 2012, source: SDG&E, 2012b)

		tariff the same year round
NG (GN-3)	**fixed ($/month)^^**	$10.00
	energy ($/kWh)	avg $0.01749/kWh and $0.01780/kWh outside/inside SD)

12.6.1.3 Seasonal and TOU definitions in SDG&E territory

Table 12-11. SDG&E seasonal and TOU definitions (eff. Oct 1 2007; applicable to electricity only, source: SDG&E, 2012c)

* summer	
peak:	11:00 am to 6:00 pm, weekdays excluding holidays
partial peak:	6:00 am to 11:00 am AND 6:00 pm to 10:00 pm, weekdays excluding holidays
off-peak:	10:00 pm to 6:00 am, weekdays; all day weekends, and holidays
* winter	
peak:	5:00 pm to 8:00 pm, Weekdays excluding holidays
partial peak:	6:00 am to 5:00 pm AND 8:00 pm to 10:00 pm weekdays excluding holidays
off-peak:	10:00 pm to 6:00 am, weekdays; all day weekends, and holidays

12.6.2 Southern California Edison and Southern California Gas

A summary of available SCE electricity tariffs is shown in Table 12-12. Within the SCE territory, non-residential electricity customers are placed into one of the following categories based on maximum demand.

Table 12-12. Available SCE electricity tariffs (source: SCE, 2012a)

schedule	max demand	time and facility demand charge	CPP	other notes
GS-1	up to 20 kW	no	no	
TOU-GS-1	up to 20 kW	yes	no	
GS-2	between 20 and 199 kW	time no, facility yes	no	the only one in the GS-2 family of tariffs without an energy TOU charge
GS-2-A	between 20 and 199 kW	time no, facility yes	no	
GS-2-B	between 20 and 199 kW	yes	no	
GS-2-R	between 20 and 199 kW	yes	no	install, own or operate solar, wind, fuel cell, or other renewable as defined by the California Solar Initiative (CSI) or Self-Generation Incentive Program (SGIP), and renewable generating capacity equal to or greater than 15 percent of the customer's annual peak demand
TOU-GS-3	200 to 499 kW	yes	yes, optional	special rate for those who install and operate onsite renewable DG
schedule	**max demand**	**time and facility demand charge**	**CPP**	**other notes**
TOU-GS-3-SOP (Super Off Peak)	200 to 499 kW	yes	no	Super Off-Peak: Midnight to 6:00 a.m. all year, everyday
TOU-8-A	500 kW+	time no, facility yes	no	must participate in Permanent Load Shifting or cold iron pollution mitigation.
TOU-8-B	500 kW+	yes	yes, optional	
TOU-8-R	500 kW to 4 MW	time no, facility yes	no	install, own or operate solar, wind, fuel cell, or other renewable as defined by the California Solar Initiative (CSI) or Self-Generation Incentive Program (SGIP), and renewable generating capacity equal to or greater than 15 percent of the customer's annual peak demand
TOU-8-CPP	500 kW+	yes	yes	option for TOU-8B customers who can shift peak load in summer

12.6.2.1 Example electricity schedules in detail

Critical Peak Pricing (CPP) in the SCE territory can be called between **9** and **15 times** during summer non-weekend days. Each event lasts four hours (between 2:00 pm and 6:00 pm) and customers must be notified no later than 3:00 pm the day prior. In exchange for signing up for the CPP option, the customer pays a reduced on-peak demand charge during the whole summer season. During CPP, the demand charges increase significantly. Any of the following may trigger a CPP event day:

(1) National Weather Service's maximum recorded temperature at the Downtown Los Angeles site greater than 90 degrees by 2 PM (DST),

(2) California Independent System Operator (CAISO) Alert,

(3) Forecasts of SCE system emergencies – may be declared at the generation, transmission, or distribution circuit level

(4) Forecasts of extreme or unusual temperature conditions impacting system demand

(5) Day-ahead load and/or price forecasts

Bill protection is offered to CPP customers for the first 12 months and ensures that the customer is billed an amount no greater than if under the otherwise applicable tariff. Bill protection details can be found in the tariff sheet.

The underlying rate structure for TOU-8-CPP is the same as TOU-8, the difference between the two is that CPP has credit/charge components for CPP days. For conciseness, the tariffs are shown together in the table below.

Table 12-13. SCE electricity tariff TOU-8-B and TOU-8-CPP for customers with loads above 500 kW (filed Dec 27 2011; source: SCE, 2012b)

		summer (JUN - SEP)			winter (Oct -MAY)		
		on peak	mid peak	off peak	on peak	mid peak	off peak
electricity (TOU-8-B) below 2kV	**fixed ($/Month)**	$577.22					
	energy ($/kWh) gen + delivery	$ 0.13990	$ 0.08850	$ 0.05629		$ 0.07779	$ 0.05278
	demand charge (per kW)	$ 16.08	$ 4.53				
	non-coincident demand charge ($/kW month)	$ 12.56			$ 12.56		
(TOU-8-CPP) option for TOU-8-B)	CPP Event Energy Charge ($/kWh)	$ 1.36					
	On-Peak Demand Credit ($/kW)	$ (12.47)					
	Maximum Available Credit ($/kW)	$ (21.87)	$ (8.16)				

12.6.2.2 Natural gas schedules

The gas rate is separated into three tiers depending on usage (0 to 100 or 250 therms/mo for summer and winter; 251 to 4167 therms/mo year round; and over 4168 therms/mo year round). For our purposes, the therms have been converted to kWh and the tiers averaged. Customers within the city of Los Angeles, Ventura, and those outside of LA and Ventura pay different rates due to the municipal surcharges.

Table 12-14. SoCalGas natural gas tariff (eff. Jan 10 2012, source: SoCalGas, 2012a)

		summer (APR - NOV)	winter (DEC - MAR)
NG (G-10/GN-10)	**fixed ($/day)**	$0.49315/day	
	energy ($/kWh)	$.018 to $.032, avg $.021	

12.6.2.3 Seasonal and TOU definitions in SCE territory

Summer season for electricity starts June 1 at 12:00 am and ends October 1 at 12:00 am. Winter season encompasses all others.

Table 12-15. SCE electricity time period definitions (eff. Mar 3 2011, source: SCE 2012b)

On-Peak:	Noon to 6:00 p.m. summer weekdays except holidays
Mid-Peak:	8:00 a.m. to Noon and 6:00 p.m. to 11:00 p.m. summer weekdays except holidays
	8:00 a.m. to 9:00 p.m. winter weekdays except holidays

Off-Peak:	All other hours.
CPP Event Periods:	2:00 p.m. to 6:00 p.m. summer weekdays except holidays during a CPP-Event only
CPP Non-Event Periods:	Summer On-Peak periods when a CPP Event is not occurring

12.6.3 Pacific Gas and Electric

A summary of available PG&E electricity tariffs is shown in Table 12-16.

Table 12-16. Available PG&E electricity tariffs (source: PG&E 2012a)

schedule	max demand *	TOU demand charge **	PDP	other notes
A-1	< 200 kW	yes	**optional**	
A-6	200 to 499 kW	yes	yes, or opt-out	
A-10	200 to 499 kW			
E-19	500 to 999 kW	yes	yes, or opt-out	
E-20	1000 kW+	yes	yes, or opt-out	

*Details of how max demand is determined can be found in the tariff sheets. ** In general, TOU demand charges are mandatory for customers with 12 months of billing history and who have opted out of PDP.

12.6.3.1 Example electricity schedules in detail

Table 12-17. PG&E E-19 secondary (eff. Jan 1 2012, source: PG&E, 2012b)

		summer (May - Oct)			winter (Nov - Apr)		
		on peak	mid peak	off peak	on peak	mid peak	off peak
electricity - (E-19) TOU Secondary	**fixed ($/day)**	$25.29775					
	energy ($/kWh)	$0.13413	$0.09516	$0.06965		$0.09000	$0.07257
	PDP energy charge ($/kWh)	$1.20			$1.20		
	PDP energy credit ($/kWh)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	demand charge (per kW)	$14.70	$3.43	$0.00	$0.00	$0.21	$0.00
	non-coincident demand charge ($/kW month)	$11.85			$11.85		
	PDP demand credit ($/kW)	($6.35)	($1.37)	$0.00	$0.00	$0.00	$0.00

Table 12-18. PG&E E-19 primary (eff. Jan 1 2012, source: PG&E, 2012b)

		summer (May - Oct)			winter (Nov - Apr)		
		on peak	mid peak	off peak	on peak	mid peak	off peak
electricity - (E-19) TOU Primary	**fixed ($/day)**	$38.43943					
	energy ($/kWh)	$0.12460	$0.09080	$0.07066		$0.08698	$0.07307
	PDP energy charge ($/kWh)	$1.20			$1.20		
	PDP energy credit ($/kWh)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	demand charge (per kW)	$14.48	$3.15	$0.00	$0.00	$0.40	$0.00
	non-coincident demand charge ($/kW month)	$9.23			$9.23		
	PDP demand credit ($/kW)	($6.09)	($1.18)	$0.00	$0.00	$0.00	$0.00

Table 12-19. PG&E E-12 secondary (eff. Jan 1 2012, source: PG&E, 2012b)

		summer (May - Oct)			winter (Nov - Apr)		
		on peak	mid peak	off peak	on peak	mid peak	off peak
electricity - (E-20) TOU Secondary	**fixed ($/day)**	$33.83984					
	energy ($/kWh)	$0.12358	$0.09078	$0.06916		$0.08612	$0.07003
	PDP energy charge ($/kWh)	$1.20			$1.20		
	PDP energy credit ($/kWh)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	demand charge (per kW)	$14.32	$3.15	$0.00	$0.00	$0.23	$0.00
	non-coincident demand charge ($/kW month)	$11.72			$11.72		
	PDP demand credit ($/kW)	($6.18)	($1.25)	$0.00	$0.00	$0.00	$0.00

12.6.3.2 PDP

This section describes some of the characteristics of PG&E's Peak Day Pricing (PDP). The following text is sourced heavily from section 17 of the E-20 tariff.

Program days: Between **9 and 15 PDP days** to be called any calendar year. Notifications are issued by PG&E by 2:00 p.m. day-before PDP event day. The PDP program will operate **year-round** and PDP events may be called for any day of the week. PDP events last from 2:00 p.m. to 6:00 p.m.

Event triggers: Events triggered by: (1) the average of the day-ahead maximum temperature forecasts for San Jose, Concord, Red Bluff, Sacramento and Fresno. Weekday trigger = 98 deg, Weekend/holiday trigger = 105 deg. (2) CAISO emergency conditions. (3) Extremely high market prices. (4) Testing / Evaluation purposes.

Event cancellation: PG&E may initiate the cancellation of a PDP event before 4:00 p.m. the day-ahead of a noticed PDP event. If PG&E cancels an event, it will count the cancelled event toward the PDP limits.

Capacity reservation: During summer season, customer can opt to operate under a "capacity reservation" scheme. This means that the customer picks a kW amount (PG&E defaults to 50% of past summer's peak demand) that is set as the capacity reservation. Usage below reservation during a PDP will not be affected by the PDP charges/credits, and customer is billed by take-or-pay for the full kW amount of capacity reservation. Usage above the capacity reservation will be subject to the PDP demand and energy charges. Capacity reservation kW can be changed once a year.

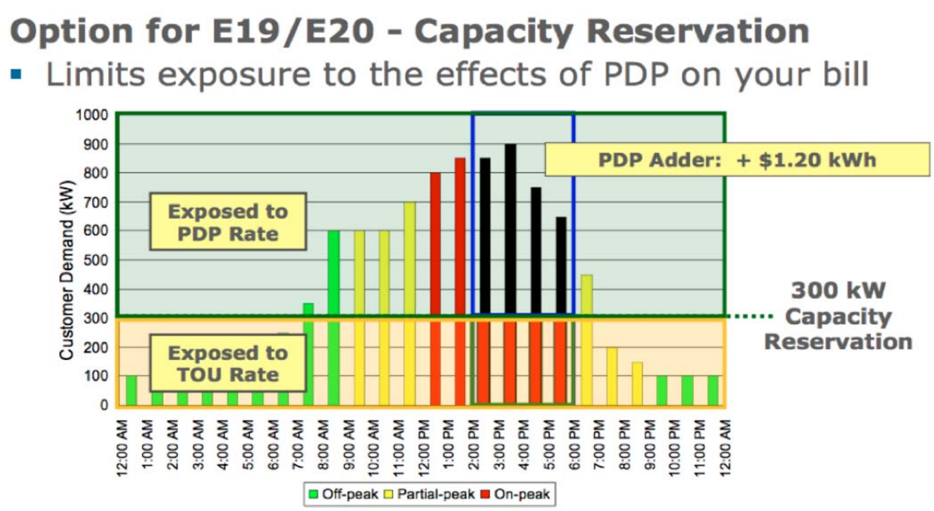

Figure 12-7.Capacity Reservation for Peak Day Pricing (source: PG&E, 2011)

12.6.3.3 Natural gas schedules

Table 12-20. PG&E G-NR1 and G-NR2 gas tariffs (eff. Jan 1 2012, source: PG&E, 2012c)

		summer (Apr - Oct)	winter (Nov - Mar)
G-NR-1 (up to 20,800 therms)	**fixed ($/day)**	from $0.27048 to $2.14936	
	energy ($/kWh)	$ 0.025817	0.027555
		summer (Apr - Oct)	winter (Nov - Mar)
G-NR-2 (20,800 therms and above)	**fixed ($/day)**	$4.95518	
	energy ($/kWh)	$ 0.027102	$ 0.028841

12.6.3.4 Seasonal and TOU definitions in PG&E territory

Table 12-21. PG&E electricity seasons and TOU definitions (eff. Mar 1 2011, source PG&E, 2012b)

summer (May to October)	
peak:	12:00 noon to 6:00 pm, Mon - Fri excluding holidays
partial peak:	8:30 am to 12:00 noon AND 6:00 pm to 9:30 pm, Mon - Fri excluding holidays
off-peak:	9:30 pm to 8:30 am, Mon - Fri, and all day on Sat, Sun, and holidays
winter (November to April)	
partial peak:	8:30 am to 9:30 pm, Mon - Fri excluding holidays
off-peak:	9:30 pm to 8:30 am, Mon - Fri, and all day on Sat, Sun, and holidays

12.6.3.5 Closed and special tariffs

Table 12-22. closed and special tariffs

IOU	schedule	customer	notes
SDG&E	AD	>= 20 and < 500 kW	closed to new customers 06/30/87
SDG&E	A-TOU	< 40 kW	closed to new customers after 10/1/2022
SDG&E	AY-TOU	< 500 kW	closed to new customers after 09/2/1999
SDG&E	DG-R	1000 kW+	DG installed that meets 10% of peak load or more.
SDG&E	BIP	-	incentive program available to customers who can commit to curtailing at least 15% of monthly peak demand (min drop of 100 kW) when requested.
IOU	**schedule**	**customer**	**notes**
SDG&E	CBP	20 kW +	incentive program, between May 1 and October 31, customer elects to drop load for an agreed upon number of hours (between 1 and 8) in exchange for incentive payments
SCE	CBP	500 kW +	incentive program, between May 1 and October 31, customer elects to drop load for an agreed upon number of hours (between 1 and 8) in exchange for incentive payments
SCE	CPP	<200 kW	incentive program, summer only
SCE	BIP	200 kW +	incentive program available to customers who can commit to curtailing at least 15% of max demand (min drop of 100 kW)
SCE	RTP-2	500 kW +	real time pricing
SCE	DBP	200 kW +	commit to reducing a min of 30 kW per hour during a DBP event
PG&E	E-BIP		incentive program available to customers who can commit to curtailing at least 15% of max demand (min drop of 100 kW
PG&E	E-CBP		incentive program, between May 1 and October 31, customer elects to drop load for an agreed upon number of hours (between 1 and 8) in exchange for incentive payments
PG&E	E-DBP	200 kW +	commit to reducing a min of 50 kW per hour during a DBP event

* In general, customer cannot participate in multiple optional tariffs simultaneously.

12.7 Historical natural gas prices

Since the natural gas prices have been very volatile in recent years the forecast of the natural gas prices in 2020 and 2030 will be difficult. These forecasts will be done until end of February 2012 (deliverable: Forecasts and Scenario Memo).

To get a better overview about the historic volatility, the historic natural gas prices for PG&E have been collected.

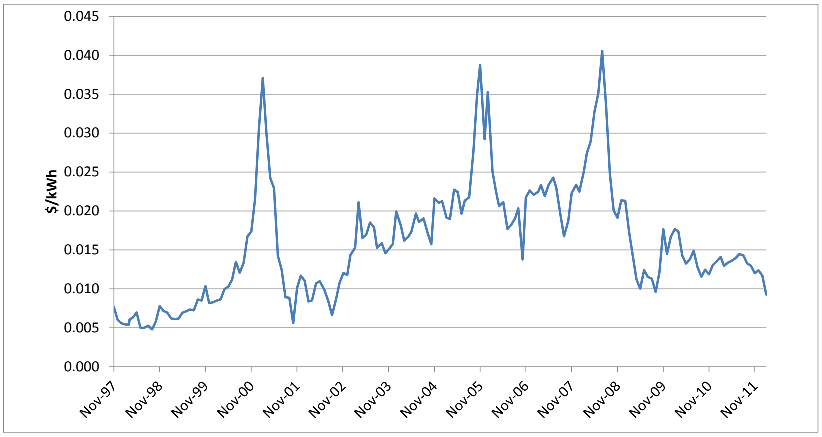

Figure 12-8. PG&E core procurement weighted average cost of natural gas (WACOG) (source: PGE, 2012d)

12.8 Technology performance data and costs

Current technology costs and performance data, available from previous projects will be updated (Stadler et al., 2010). An important source to be mentioned here is the *Cost-Effectiveness of Distributed Generation Technologies* report of the CPUC Self-Generation Incentive Program (CPUC, 2011). Projections underlying the Annual Energy Outlook 2009 – 2011 will be used to estimate future technology costs and performances. These forecasts will be done until end of February 2012 (deliverable: Forecasts and Scenario Memo).

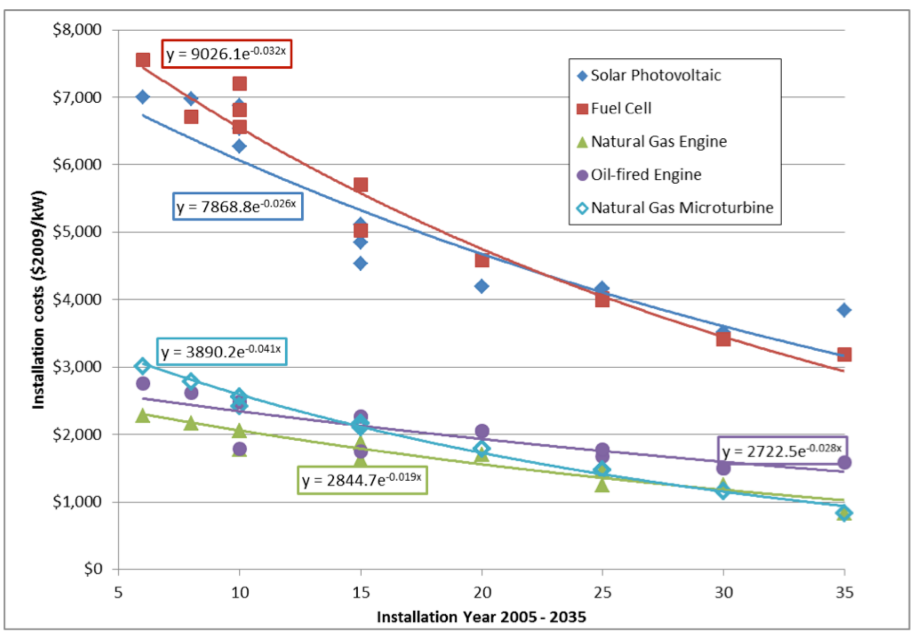

Figure 12-9. Installation cost based on projections of the Annual Energy Outlook 2009 – 2011 (source: AEO 2009-2011, own calculations)

12.9 Marginal macro-grid CO_2 emissions

Previous studies used Marnay et al., 2002 and Mahone et al., 2008 data. However, the Mahone et al., 2008 does not project the average and marginal macro-grid CO_2 emissions out to 2030. Therefore, we tried to contact Martha Brook from CEC who supposedly has a project with ICF on this topic. This information is based on a phone call with Chris Scruton. However, so far we have not heard anything back from Martha Brook.

12.10 Solar radiation

Solar radiation data will be based on Stadler et al., 2010.

12.11 Significant challenges and problems observed

The biggest problem is the limited CEUS database information, especially for the restaurant sector. For this project Berkeley Lab would need the hourly load profiles for all major restaurants considered/simulated with eQuest within CEUS.

We kindly request these information to be released by CEC and ITRON to improve the quality of this project.

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12.13 Acronyms

AEO	Annual Energy Outlook
CAISO	California Independent System Operator
CBP	capacity bidding program (SDG&E)

CCHP	combined cooling, heating, and electric power
CEUS	California Commercial End-Use Survey
CHP	combined heat and power
CSI	California Solar Initiative
CPP	critical peak pricing
DER	distributed energy resources
DER-CAM	Distributed Energy Resources Customer Adoption Model
DG	distributed generation
EECC	electric energy commodity cost (SDG&E)
LADWP	Los Angeles Department of Water and Power
PG&E	Pacific Gas and Electric
SCE	Southern California Edison
SDG&E	Diego Gas and Electric
SGIP	Self-Generation Incentive Program
SUMD	Sacramento Municipal Utility District
TOU	time of use

13 Appendix III: Forecasts and Scenarios Memorandum

Forecasts and Scenarios Memorandum for task 2.8

Encouraging Combined Heat and Power in California Buildings

CEC 500-10-052, task 2.8

Principal Investigator: Michael Stadler
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LBNL Project Team: Michael Stadler, Judy Lai, Markus Groissböck, Andreas Müller, Gonçalo Cardoso, Chris Marnay, Nicholas DeForest

13.1 Background

The goal of task 2.8 is to stimulate economic and environmentally sound natural gas-fired combined heat and power (CHP) and combined cooling, heating, and electric power (CCHP) adoption in California's medium sized *commercial building sector*.

Compared to other studies, this analysis will not be done in isolation and will consider other distributed energy resources (DER) technologies such as PV, solar thermal, electric and heat storage, which can be in competition with CHP and CCHP or supplement each other, depending on the building type and DER adoption strategy.

For this analysis the Distributed Energy Resources Customer Adoption Model (DER-CAM) from Lawrence Berkeley National Laboratory will be used. DER-CAM is a mixed-integer linear program (MILP) written and executed in the General Algebraic Modeling System (GAMS) (Stadler et al., 2010). Its objective is typically to minimize the annual costs or CO_2 emissions for providing energy services to the modeled site/building, including utility electricity and natural gas purchases, plus amortized capital and maintenance costs for any distributed generation (DG) investments. Other objectives, such as carbon or energy minimization, or a combination are also possible. The approach is fully technology-neutral and can include energy purchases, on-site conversion, both electrical and thermal on-site renewable harvesting, and end-use efficiency investments.

For more information on DER-CAM please refer to the "Collected Data Memorandum" from January 2012 and DER-CAM, 2012.

13.2 Aspects considered in this project

Berkeley lab will

- perform optimization runs for 2030 and update existing 2020 runs (Stadler et al., 2010)
- develop multiple scenarios that reflect grid de-carbonization, changes in equipment performance, and regulatory environment; besides CO_2 emissions also NOx emissions will be considered in the DER-CAM runs
- consider zero net energy buildings and their impact on CHP and CCHP
- consider different feed-in tariffs
- consider the impact of CO_2 pricing (e.g. cap-and-trade) on CHP/CCHP adoption

- put a special focus on the California restaurant sector since it is a major consumer of natural gas.

13.3 Data needed for the DER-CAM runs

To perform the described analysis with DER-CAM following data will be needed:

- hourly electricity, heating, cooling, domestic hot water, and cooking demand for the selected representative commercial buildings; the buildings will be selected from CEUS.
- electric and natural gas tariffs
- technology performance data and costs for the selected DER technologies
- CO_2 emissions of the macro-grid to assess the CO_2 mitigate potential of CHP and CCHP and other DER
- solar radiation for different locations in California to be able to consider the impact of PV and solar thermal on CHP/CCHP adoption.
- Energy Policies influencing the CHP/CCHP adoption, e.g. Self-Generation Incentive Program (SGIP)

Important influencing factors on the technology adoption in 2020 and 2030 are the technology performance as well as the regulation framework for the cap-and-trade system, possible Self-Generation Incentive Program (SGIP) in California and feed-in tariffs.

13.4 Objective of this memorandum

Since this project will perform multiple scenarios for the different policy measures, which might impact the CHP/CCHP adoption a special focus will be put on the

- cap-and-trade system
- SGIP
- feed-in tariffs

Furthermore, forecasted technology performance in 2020 and 2030 will be shown.

Please note that all data described in this memorandum are subject to updates/changes in course of the project. Task 2.8 started on Jan 1 2012 and the “Forecasts and Scenarios Memorandum” is the second deliverable within this task.

13.5 AB 32 and cap-and-trade

Assembly Bill 32 (AB 32), the Global Warming Solutions Act, was signed in 2006 and set greenhouse gas (GHG) emission goals for California to year 2020 that included penalties for non-compliance. The covered GHG are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), nitrogentrifluoride (NF_3), and other fluorinated greenhouse gases. (CARB 2011b).

Cap-and-trade is one of the market mechanisms to be used by California to arrive at full compliance with AB 32 and takes into account the sources (referred to as covered entity, business, or facility in later sections of this document) that are responsible for approximately 85% of the emissions in California (CARB, 2010a). The California Air Resources Board (CARB) oversees the cap-and-trade program.

13.5.1 Scope of cap-and-trade program (for AB 32 compliance, to year 2020)

Phase 1 of the cap-and-trade program began in 2012. Covered entities for both Phase I and 2 must *register* for the program by end of January 2012 (CARB, 2012a). The first compliance period[11] includes electricity generation/importer and *large industrial* emitters that exceeded 25,000 mtCO_2e per year from 2008 to 2012[12] (CARB, 2012a). Phase 2 will begin in 2015 and include *fuel distributers* those under 25,000 mtCO_2e (CARB, 2010b, EPA, 2009, CARB, 2012a). Relevant details regarding the scope and the cap are given below (CARB, 2011a).

13.5.1.1 Scope

- Program covers about 350 businesses, representing 600 facilities. Uncovered businesses and facilities may voluntarily opt-in to the program.
- Compliance period 1 starts in 2013 for electric utilities and large industrial facilities.
- Compliance period 2 starts in 2015 for distributors of transportation, natural gas and other fuels. Cap increased to accommodate for new entrants.
- Designed to link with similar trading programs in other states and regions. See Western Climate Initiative (WCI) below.

Note that ARB proposes the 'first deliverer approach', i.e., the regulation applies to the first responsible party for placing power onto the California grid. For in-state electricity generation, the covered entity is the source of generation; for imported electricity, the covered entity will be the first entity to place power onto the California grid (CARB 2010b). With this approach, the emissions from electricity generation *and usage* will be attributed to electric utilities. What remains unaccounted for is the emissions from natural gas combustion, e.g., for building heating and CHP.

13.5.1.2 The cap/allowances

The initial cap for 2012 will be set at 162.8 million mtCO_2e and decline until 2015. In 2015, cap will be raised to 394.5 million mtCO_2e to accommodate for the new covered entities and again decline until 2020 (CARB 2010b). See Table 13-1 for details.

- Caps set in 2013 at about 2 percent below the emissions level forecast for 2012.
- Declines about 2 percent in 2014.
- Declines about 3 percent annually from 2015 to 2020, from 394.5 to 334 million mtCO2e.

Table 13-1. California GHG allowances budget (source: CARB, 2011b)

	year	GHG allowances (cap) (millions)
1st compliance	2013	162.8

[11] "A *compliance period* is the length of time for which covered entities must submit compliance instruments equal to their verified emissions." (CARB, 2010b).

[12] Yearly emissions reporting to US EPA required of certain industries. For a list of example industries, please refer to Table 1 and Table 2 of (EPA 2009). If under 25,000 mtCO_2e/yr for five consecutive years, facility can cease reporting. If under 15,000 mtCO_2e/yr for three years, facility can cease reporting. Nevertheless, facility emission monitoring is required (so it can know if it goes above 25,000). The Cal/EPA (also with a MRR) and CARB have aligned the covered entity's emissions limit of the cap-and-trade program with that of the US EPA reporting threshold.

	2014	159.7
2nd compliance	2015	394.5
period	2016	382.4
	2017	370.4
3rd compliance	2018	358.3
period	2019	346.3
	2020	334.2

13.5.1.3 Emissions threshold for reporting and participating in cap-and-trade

According to the US EPA's Final Rule on Mandatory Reporting of Greenhouse Gases (EPA, 2009), several GHG reporting thresholds on the national level were evaluated: 1,000 mtCO_2e, 10,000 mtCO_2e, 25,000 mtCO_2e, and 100,000 mtCO_2e. The 25,000 threshold was found to be the most suitable and pragmatic; it captures approximately 85% of national emissions. If 1,000 mtCO_2e were used, the number of entities reporting would grow by an order of magnitude while capturing less than 10% of the national emissions. If 10,000 mtCO_2e were used, the number of reporting entities would double and capture only one more percent of national emissions. If 100,000 mtCO_2e were used, certain key sectors of the economy would be excluded all together. Recognizing the lack of benefits from decreasing or increasing the threshold and to align with the national GHG reporting requirements, the emissions reporting as well as cap-and-trade threshold for California was set also at 25,000 mtCO_2e.

This emission threshold sensitivity is very important for our project since it suggests that it will be very unlikely that the 25,000 mtCO_2e threshold will be changed in the near future (except for fuel distributers, see above). As mentioned in the "Collected Data Memorandum" this project will use the California Commercial End-Use Survey (CEUS) database as basis for the DER-CAM load profiles for buildings between 100 kW and 5 MW electric peak loads. The next steps will look into the annual CO_2 emissions from natural gas of the CEUS buildings and it will be decided if the buildings will be covered by the cap-and-trade system. There is a possibility that the adoption of CHP will increase the CO_2 emissions above the 25,000 mtCO_2e threshold. The emissions from electricity production are covered by the utility and offsets due to CHP are not considered and this creates a disadvantage for CHP systems.

However, the cap-and-and trade system will influence the electricity and natural gas price, and therefore, the impact on the energy prices will be considered.

13.5.2 Cap and trade in the Western Climate Initiative

The Western Climate Initiative (WCI, 2012a, see map in Figure 13-1) was established in 2007 and collectively the region set an emissions target of 15% below 2005 levels by 2020 (PEW, 2009 and WCI, 2012a, 2012b). The first phase of WCI's cap-and-trade program began on January 1 2012 and includes emitters from the electricity generation sector, industrial sources and processes, etc. Phase two will begin in 2015 and expand to include the transportation sector, commercial[13], residential, and others. The program is expected to be fully implemented in 2015 (WCI, 2012b). This program covers 90% of emissions in WCI area.

[13] Please note that this might contradict the EPA emission threshold sensitivity analysis (EPA, 2009).

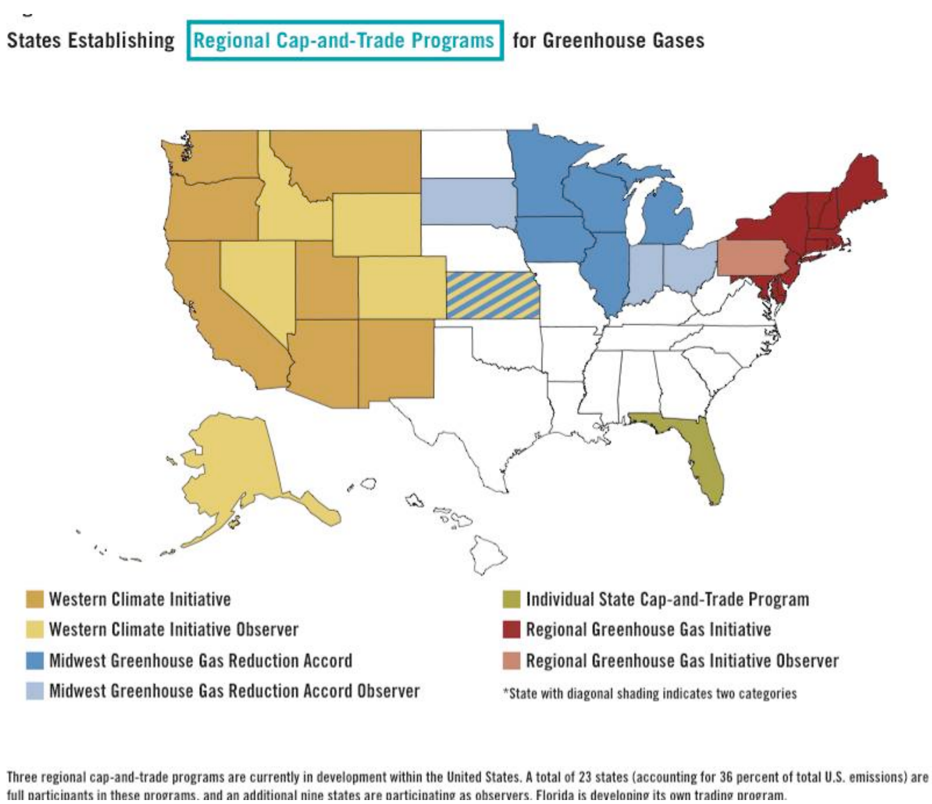

Figure 13-1. Map showing states' cap-and-trade status (PEW, 2009)

13.5.3 Future cap-and-trade program?

Executive Order S-3-05 was signed by Governor Schwarzenegger on June 1 2005, which set out several GHG goals (Caltrans, 2005):

- GHG emission reduction target for 2010 = reduced to 2000 emission levels.
- GHG emission reduction target for 2020 = reduced to 1990 emission levels.
- GHG emission reduction target for 2050 = reduced to 80% below 1990 emission levels. The 2050 goal will not be possible with just cap-and-trade; it will require participation from the transportation sector, new technologies to advance energy efficiency, etc. (LBNL, 2011).

13.5.4 Definitions

Most definitions are copied word for word from the sources cited while some have minor changes and added clarifications.

Allowances: tradable permits, equal to the cap, declines over time. Each allowance equals one metric ton of carbon dioxide equivalent. (CARB, 2010b)

Allowance Price Containment Reserve (Reserve or reserves): an account that is filled with a specified number of allowances removed from the overall cap at the beginning of the program. Covered entities may purchase these at specified prices during direct quarterly sales. Covered entities gain flexibility through access to the Reserve if prices are high or entities expect prices to be high in the future. The Reserve is proposed be filled with 123.5 million allowances out of the total of approximately 2.7 billion issued for the years 2012 to 2020. In addition, one percent of the allowances from 2013-2014, four percent of the allowances from 2015-2017, and seven percent of the allowances from 2018-2020 will be transferred to the Reserve. (CARB 2010b, CARB 2011b).

Banking: holding onto spare allowances for use in a later compliance period. (CARB, 2010b)

Cap: the limit put on the amount of GHGs that can be emitted by all covered sectors; the total number of allowances created is equal to the cap set for cumulative emissions from all the covered sectors. (CARB, 2010b)

Compliance instrument: allowances and offsets, may be traded by entities. (CARB, 2010b)

Compliance period: the length of time for which covered entities must submit compliance instruments equal to their verified emissions. (CARB, 2010b)

Offsets (or **offset credits**): is a credit that represents a reduction of greenhouse gases resulting from an activity that can be measured, quantified, and verified. Each offset credit represents a specific quantity of emissions reductions from a source not directly covered by the cap-and-trade program (but can be used to meet compliance). Program proposes a maximum of 232 mtCO_2e of offsets through the year 2020. Up to 8% of a covered entity's compliance obligation may be met by offsets. (CARB, 2010b).

13.6 Self-Generation Incentive Program (SGIP)

The California Public Utilities Commission (CPUC) improved and streamlined its Self-Generation Incentive Program (SGIP), including modifying eligibility criteria and incentive amounts and payment structures for eligible technologies on September 8, 2011.

Eligibility for participation in the SGIP will now be based on greenhouse gas (GHG) emissions reductions. Technologies that achieve reductions of GHG emissions will be eligible for the program, including wind turbines, fuel cells, organic rankine cycle/waste heat capture, pressure reduction turbines, advanced energy storage, and combined heat and power gas turbines, micro-turbines, and internal combustion engines.

Participants will receive up-front and performance-based incentives (PBI). The incentives will apply only to the portion of the generation that serves a project's on-site electric load.

The SGIP has been extended from January 1, 2012, to January 1, 2016.

Only self-generation equipment installed on the Host Customer's side of the Electric Utility meter is eligible.

13.6.1 2011 Self-Generation Incentive Program

All information is taken from the SGIP Handbook, 2011.

13.6.1.1 Requirements

1. Eligibility: Based on greenhouse gas (GHG) reductions.
   - Non-renewable CHP eligibility determined on project-by-project basis.
   - Electric-only technologies using fossil fuels will need certification of performance according to a testing protocol.
2. GHG baseline: 349 kg CO_2/MWh. This avoided emission factor does not account for avoided transmission and distribution losses**. The actual on-site emission rate that projects must beat to be eligible for SGIP participation is 379 kg CO_2/MWh**. Eligibility is determined based on a cumulative 10 years performance. This means that a lifetime of 10 years must be considered for calculating the average efficiency and/or the CO_2 emissions. A warranty of 10

years has to be provided.

3. SGIP Incentive Levels by Category

Table 13-2: Incentive levels by categories

technology type	incentive ($/W)
wind turbine	1.25
waste heat to power	1.25
pressure reduction turbine	1.25
internal combustion engine - CHP	0.50
micro turbine - CHP	0.50
gas turbine - CHP	0.50
advanced energy storage	2.00
biogas	2.00
fuel cell - CHP or electric only	2.25

Advanced Energy Storage can be stand-alone or paired with solar PV or any otherwise eligible SGIP technology. Biogas incentive is an adder that may be used in conjunction with fuel cells or any conventional CHP technologies.

4. Storage Eligibility: Stand-alone as well as paired with SGIP eligible technologies or PV. Advanced Energy Storage (AES) must be able to discharge its rated capacity for a minimum of 2 hours
5. Biogas Eligibility: on-site and in-state directed.
   - Directed biogas contracts must be for a minimum of ten years, and provide a minimum of 75% of the total energy input required each year.
   - On-site biogas must also provide 75% of the total energy input required each year.
6. System size: No minimum or maximum size restrictions given that project meets onsite load. However, for capacities above 3 MW the incentive is zero.
   Wind & renewable-fueled fuel cell: 30kW minimum, smaller projects may apply to the California Energy Commission's Emerging Renewables Program.
7. Payment Structure: 50% upfront, 50% PBI based on kWh generation of on-site load.
   - Projects under 30 kW will receive the entire incentive upfront.
   - Projects will be subject to a 5% band for GHG emission rate.
   - No penalty is assessed in any year that cumulative emissions rate does not exceed 398 kg CO_2/MWh.
   - PBI payments will be reduced by half in years where a project's cumulative emission rate is greater than 398 kg CO_2/MWh but less than or equal to 417 kg CO_2/MWh.
   - Projects that exceed an emission rate of 417 kg CO_2/MWh in any given year will receive no PBI payments for the year.
   - Assumed Capacity Factors: 10% for AES, 25% for wind, and 80% for all other distributed

energy resources (DER). DER which does not achieve this capacity factor over five years will not be paid full PBI. The upfront payment if fixed.

8. Incentive Decline: 10% per year for emerging technologies and 5% per year for all other technologies, beginning 1/1/2013.
9. Supplier Concentration: No more than 40% of the annual statewide budget available on the first of a given year may be allocated to any single manufacturer's technology during that year. The initial 40% limit will cover the period from the launch of the new program through 2012 and will be calculated based on the total funding available when the program is reinstated plus any additional funds collected in 2012, if applicable.
10. Maximum project incentive: $5 million
11. Minimum customer investment: Must be 40% of eligible project costs. SGIP portion of project cost based on the following formula: 1-applicable Investment Tax Credit (ITC)-0.4
    The biogas adder does not count toward above limit for projects using DBG. Instead, the adder is applied separately to the cost of the biogas contract and will not exceed the cost difference between the biogas contract and a similar contract for standard natural gas.
12. Budget Allocation: 75% renewable and emerging technologies, 25% non-renewable.
13. Program Administration Budget: The Program Administration Budget will be reduced to 7%.
14. Export to Grid: 25% maximum on an annual net basis.
15. Energy Efficiency Audit: Mandatory for participation in SGIP unless an extensive audit has been conducted within five years of the date of the reservation request. Any measures with a payback period of two years or less shall be implemented prior to receipt of the upfront incentive payment. Exceptions may be granted by the Program Administrator if documentation is submitted by the applicant explaining why implementation of the measure(s) was not feasible.
16. Application Fees: 1% of the amount of incentive requested
17. Extensions: All projects must be limited to one, six-month extension. A request for second extension will be made to the SGIP Working Group for approval.
18. Warranty: Ten-year warranty required.

13.6.1.2 Further requirements

- Power Factor (PF) Specification (micro turbines, internal combustion engines & gas turbines)
  When applicable, applications must include self-generating facility design specifications and/or manufacturer's specifications which show that the system will be capable of operating between 0.95 PF lagging and 0.90 PF leading.
- 60% Minimum System Efficiency Specification The application must include manufacturer specifications and calculations substantiating that the minimum system efficiency of the generator is equal or greater than 60% must be included.

13.6.1.3 Calculating the Incentive

Projects under 30 kW in size will only receive an upfront incentive of 100%.

For projects that are larger than 30 kW in size the SGIP will pay 50% of the incentive upfront. A performance based incentive (PBI) will cover the remaining 50%. Annual kilowatt hour based payments will be structured so that under the expected capacity factor, a project would receive the entire stream of performance payments in five years. To calculate the basis ($/kWh) of the annual PBI payments, the following formula is used:

$/kWh = remaining 50% of incentive / total anticipated kWh production (1)

total anticipated kWh production = nameplate capacity x capacity factor x hours per year x five years (2)

For a 5-year period the PBI payment will be paid annually based on recorded kWh of electricity produced over the previous 12 months and the PBI basis:

$$\text{PBI Payment} = \$/\text{kWh x actual annual kWh} \quad (3)$$

The capacity factors are fixed and are given by the table below.

Table 13-3: Assumed capacity factors

technology type	capacity factor
advanced energy storage	10%
wind turbine	20%
all other technologies	80%

The hours per year are fixed with 8760.

13.6.1.4 Limited PBI based on GHG reduction

emission rate ≤ 398 kg CO_2/MWh → no penalty on PBI payment

398 kg CO_2/MWh ≤ emission rate ≤ 417 kg CO_2/MWh → PBI payment reduced by 50%

emission rate ≥ 417 kg CO_2/MWh → no PBI payment.

13.6.1.5 Tired incentives and incentive decline

For projects that are greater than 1 MW up to 3 MW, the incentive declines as identified in Table 13-4. SGIP incentive levels will decline annually with the first reduction starting on January 1, 2013. The rate of incentive decline is provided in Table 13-5. The full incentive is paid for systems up to 1 MW. The second MW of capacity receives 50% of the base incentive rate per W, and the third MW receives 25% of the base incentive rate. For hybrid systems (e.g. systems with multiple technologies), with total capacities exceeding 1 MW, the technology with the lowest incentive rate is ordered first in considering the decline in incentives (e.g. for a 1 MW GT and a 300 kw fuel cell, the 1 MW GT would receive 100% of the base rate, the fuel cell would receive 50% of the base rate).

Table 13-4: Tired incentive rates

capacity	incentive rate (% of base)

0 - 1 MW	100%
1 - 2 MW	50%
2 - 3 MW	25%

Table 13-5: Total incentive decline[14]

technology type	yearly incentive decline Rate
renewable, waste energy recovery, conventional CHP	5%
emerging technologies	10%

13.6.1.6 System size parameters

Only information relevant for this project is shown.

Equipment must be sized to serve all or a portion of the electrical load at the site.

- Non-renewable fuel cell systems that are rated at 5 kW or less are exempt from the system sizing requirements.
- System sizing for pressure reduction turbine, waste heat to power, gas turbine, micro turbine, internal combustion engine and fuel cell projects may be sized up to the host customer's previous 12-month annual peak demand at the proposed Site.[15]
- The electricity amount exported to the grid must not to exceed 25% of self-generated electricity on an annual basis. In cases where a customer is exporting electricity to the grid, the PBI payment will be calculated based on annual on-site electrical consumption[16] as opposed to the generating system's output.

Annual PBI = \$/kWh x *capacity factor*[17] x annual on-site electrical consumption (4)

- Waste heat utilization:

$$T / (T + E) \geq 5\% \quad (5)$$

$$(E + 0.5 \times T) / F \geq 42.5\% \quad (6)$$

T…The annual useful thermal output used for industrial or commercial process (net of any heat contained in condensate return and/or makeup water), heating applications

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[14] Based on the literature it is not clear if this is a logarithmic or linear decline.

[15] Calculation of load based on electric energy (kWh) only data:
Peak demand (kW) = largest monthly bill (kWh/month) / (load factor x days/bill X 24), small commercial load factor = 0.47, agricultural load factor = 0.35.

[16] It is not clear if this means only the output from the generation, which is consumed onsite or the total on-site electrical consumption.

[17] The authors of this memo think that this equation might be wrong and that the "capacity factor" should be removed from the equation.

(e.g., space heating, domestic hot water heating), used in a space cooling application (i.e., thermal energy used by an absorption chiller).

E…The annual electric energy made available for use, produced by the generator, exclusive of any such energy used in the power production process.

F… The generating system's annual Lower Heating Value (LHV) non-renewable fuel consumption

The 0.5 factor is arbitrary and is used to legally define cogeneration systems.

- Minimum electric efficiency

$$E \;/\; F \geq 40\% \tag{7}$$

E…The generating system's rated electric capacity as defined in Section 9.2 of the SGIP handbook, converted into equivalent Btu/hr using the factor 3,414 Btu/kWh.

F…The generating system's Higher Heating Value (HHV) fuel consumption rate (Btu/hr) at rated capacity.

- Minimum system efficiency standard

$$(E + T) \;/\; F \geq 60\% \tag{8}$$

F in HHV

- NOx emission standard of 0.07 lb/MWh needs to be fulfilled.

An additional incentive of 20 percent will be provided for the installation of eligible distributed generation or Advanced Energy Storage technologies from a California supplier.

13.7 Feed-in tariffs

13.7.1 System size parameters

- The CHP system shall be sized to be no smaller than the minimum connected on-site thermal load and no larger than the maximum connected on-site thermal load.
- At least 15% thermal output over the year or thermal heat onside used ≥ 5% of facility's total annual energy output depending on the operation mode. The sequence can be thermal use followed by power production or the reverse, subject to the following standards: (a) at least 5 percent of the facility's total annual energy output shall be in the form of useful thermal energy or (b) where useful thermal energy follows power production, the useful annual power output plus one-half the useful annual thermal energy output equals not less than 42.5 percent of any natural gas and oil energy input (see equation 6).
- Net generating capacity shall be ≤ 20 MWe
- Net export capacity shall be ≤ 5 MWe
- In the CHP System efficiency requirement of 60% based on the HHV.

- CO_2 ≤ 0.37900 kg/kWhe
- CO ≤ 0.04536 kg/MWhe
- VOC ≤ 0.00907 kg/MWhe
- NOx ≤ 0.03175 kg/MWhe

13.7.2 Calculation of the feed-in tariff

Feed-in tariff = [(fixed component + variable Component) x TOD factor] x location factor (9)

Fixed component: market price referent (MPR) in $/kWh

Variable component: gas price x HR + variable O&M. Gas price specific for each utility and based on average of three bid week gas indices

HR is 6,924 Btu/kWh based on average HR from MPR

Variable O&M based on O&M adder from MPR

Time of delivery (TOD) factor (per utility) = investor owned utility (IOU)-specific factors

Location factor is 1.1 if in a "high-value area", otherwise 1.

13.7.2.1 MPR fixed component

Table 13-6: MPR fixed component (source: Source: Resolution E-4442/SVN)

adopted 2011 MPR - long-term contracts (nominal – US$/kWh)									
contract start date	5-year	6-year	7-year	8-year	9-year	10-year	15-year	20-year	25-year
2012	0.06929	0.07100	0.07258	0.07408	0.07550	0.07688	0.08352	0.08956	0.09274
2013	0.07405	0.07554	0.07697	0.07836	0.07971	0.08103	0.08775	0.09375	0.09695
2014	0.07763	0.07907	0.08048	0.08186	0.08321	0.08454	0.09151	0.09756	0.10081
2015	0.08096	0.08240	0.08381	0.08520	0.08657	0.08804	0.09520	0.10132	0.10464
2016	0.08414	0.08561	0.08705	0.08847	0.09001	0.09156	0.09883	0.10509	0.10848
2017	0.08704	0.08853	0.09001	0.09163	0.09325	0.09488	0.10223	0.10859	0.11206
2018	0.09000	0.09153	0.09323	0.09494	0.09665	0.09831	0.10570	0.11218	0.11572
2019	0.09304	0.09484	0.09664	0.09844	0.10018	0.10186	0.10928	0.11587	0.11946
2020	0.09644	0.09836	0.10025	0.10208	0.10383	0.10550	0.11296	0.11965	0.12326
2021	0.10011	0.10211	0.10403	0.10585	0.10758	0.10916	0.11675	0.12354	0.12712
2022	0.10404	0.10604	0.10793	0.10972	0.11135	0.11299	0.12067	0.12752	0.13105
2023	0.10817	0.11011	0.11195	0.11360	0.11528	0.11691	0.12469	0.13160	0.13504

13.7.2.2 MPR variable component

Table 13-7: MPR variable component (source: CPUC, 2011b)

adopted 2011 MPR - long-term contracts (nominal – US$/kWh)									
contract start date	5-year	6-year	7-year	8-year	9-year	10-year	15-year	20-year	25-year
2012	0.05012	0.05166	0.05307	0.05440	0.05567	0.05688	0.06281	0.06820	0.07283
…									
2020	0.07576	0.07751	0.07924	0.08091	0.08250	0.08401	0.09073	0.09675	0.10189

13.7.2.3 Gas forecast

Table 13-8: Gas forecasts (source: Resolution E-4442/SVN)

year	2011 henry hub forecast (nominal US$/MMBtu)	2011 CA gas forecast (nominal US$/MMBtu)
2012	4.84	5.26
2013	5.17	5.55
2014	5.44	5.82
2015	5.73	6.12
2016	6.02	6.41
2017	6.29	6.69
2018	6.56	6.97
2019	6.83	7.25
2020	7.10	7.53
2021	7.37	7.82
2022	7.66	8.11
2023	7.96	8.42
2024	8.23	8.96
2025	8.65	9.38
2026	9.06	9.80
2027	9.38	10.15
2028	9.68	10.46
2029	9.99	10.73
2030	10.12	10.83

2031	10.44	11.24
2032	10.75	11.52
2033	11.12	11.87
2034	11.46	12.23
2035	11.79	12.56
2036	12.20	12.99
2037	12.55	13.35
2038	12.92	13.73
2039	13.29	14.12
2040	13.67	14.51
2041	14.05	14.90

13.7.2.4 TOD factors

Table 13-9: TOD factor for PG&E (source: Resolution E-4442/SVN)

month	period	definition	factor
June - September	Super-Peak	13-20; Mon - Fri (except NERC holidays)	2.38
	Shoulder	7-12, 21-22; Mon - Fri (except NERC holidays) 7-22 Sat + Son (and all NERC holidays)	1.12
	Night	1-6, 23-24 all days (including NERC holidays)	0.59
October - February	Super-Peak	as above	1.10
	Shoulder	as above	0.94
	Night	as above	0.66
March - May	Super-Peak	as above	1.22
	Shoulder	as above	0.90
	Night	as above	0.61

Table 13-10: TOD factor for SDG&E (source: Resolution E-4442/SVN)

month	period	definition	factor
July - October	On-Peak	11-19; Mon - Fri (except NERC holidays)	2.50
	Semi-Peak	6-11, 19-20; Mon - Fri (except NERC holidays)	1.34
	Off-Peak	1-5, 21-24 all days and weekend (including NERC holidays)	0.80
November - June	On-Peak	13-21; Mon - Fri (except NERC holidays)	1.09
	Semi-Peak	6-13, 21-22; Mon - Fri (except NERC holidays)	0.95

	Off-Peak	1-5, 23-24 all days and weekend (including NERC holidays)	0.68

Table 13-11: TOD factor for SCE (source: Resolution E-4442/SVN)

month	period	definition	factor
June - September	On-Peak	12-18; Mon - Fri (except NERC holidays)	3.13
	Semi-Peak	8-12, 18-23; Mon - Fri (except NERC holidays)	1.35
	Off-Peak	1-7, 24 all days and weekend (including NERC holidays)	0.75
October - May	On-Peak	8-21; Mon - Fri (except NERC holidays)	1.00
	Semi-Peak	6-8, 21-24; Mon - Fri (except NERC holidays) 6-24 on weekend & NERC holidays	0.83
	Super-Off-Peak	0-6 all days (including NERC holidays)	0.61

13.7.2.5 Location factor

If the generating facility is located in a "high-value area", each Monthly Contract Payment for the entire term shall receive a location factor.

The generating facility shall be deemed to be located in a high-value area if it is interconnected to buyer's electric system at a location which, in the year of the effective date, is identified pursuant to CPUC D. 09-12-042 (as modified by other AB 1613 decisions) as a "Local Resource Adequacy" area based on the most recent CAISO Local Capacity Requirement Study adopted by the CPUC.

The recent list of the bonus areas can be found at Bonus Areas, 2011.

13.8 Required DER-CAM changes for the sensitivity runs

This section summarizes the cap-and-trade, SGIP, and feed-in tariff requirements to be able to implement them in DER-CAM.

13.8.1 Cap-and-trade system

- Report of CO_2 emissions based on on-site natural gas usage (including CHP) to be able to determine if site is subject to the cap-and-trade system based on a certain emission threshold.

13.8.2 SGIP

- CHP capacity < 30 kW: full incentive upfront, no PBI.
- CHP capacity ≥ 30 kW: 50% incentive upfront, rest over 5 years. PBI payment/year = [50% of incentive / (CHP capacity x assumed capacity factor x 8760) x real operating hours] without electric sales. With electricity export the electricity used onsite has to be considered.
- Emission constraints
  Reduction of PBI payment of 0%: emission rate ≤ 398 kg CO_2/MWh

Reduction of PBI payment of 50%: 398 kg CO_2/MWh ≤ emission rate ≤ 417 kg CO_2/MWh
Reduction of PBI payment of 100%: emission rate ≥ 417 kg CO_2/MWh

- Incentive depends on project size:
  CHP capacity ≤ 1 MW: 100% of incentive
  1 MW < CHP capacity ≤ 2 MW: 50% of incentive
  2 MW < CHP capacity ≤ 3 MW: 25% of incentive
- Maximum allowed CHP capacity = max(load('electricity-only',months,'peak',hours+ 'cooling',months,'peak',hours))
- Annual Exported Electricity ≤ 25% * Annual Onsite-Generated Electricity
- Waste Heat & Electricity Utilization:
  T / (T + E) ≥ 5%
- (E + 0.5 x T) / F ≥ 42.5% (F in LHV)
- E/F≥40% (F in HHV)
- (E + T) / F ≥ 60% (F in HHV)
- with
- T…annual useful thermal output of CHP
  E…annual generated electricity through CHP
  F…annual fuel consumption by CHP (HHV or LHV depending on the equation)
- NOx emissions ≤ 0.07 lb/MWh

13.8.3 Feed-in tariff

- CHP electric capacity ≤ 20 MW
- electricity export ≤ 5 MW
- T / (T + E) ≥ 5%
- (E + 0.5 x T) / F ≥ 42.5% (F in LHV)
- (E + T) / F ≥ 60% (F in HHV)
- FiT [$/kWh] = [(fixed Component + variable component) x TOD] x location factor
  fixed component: given depending on contract duration and start year ($/kWh)
  variable Component: gas price x HR + variable O&M ($/kWh)
  TOD: given for utility service territory
  location factor: given by CAISO (default: 1.0, for "high-value area": 1.1).

13.9 DER-CAM technology forecasts for 2020 and 2030

A summary of selected cost and performance data for 2020 and 2030 is given in Table 13-12. Most striking is that the Annual Energy Outlook for 2009-2011 is more conservative about the fuel cell cost reductions as the Annual Energy Outlook 2004.

Table 13-12. Menu of available DG and CHP equipment options in 2020 and 2030, 2008US$ (source: AEO, 2009, AEO, 2010, AEO, 2011, CPUC, 2011a, Firestone, 2004, Goldstein et al., 2003, SGIP, 2008, own calculations)

	capacity (kW)	installed costs ($US\$_{2008}$/kW)			installed costs with heat recovery ($US\$_{2008}$/kW)			variable maintenance ($US\$_{2008}$/kWh)	electric efficiency (%), (HHV)			lifetime (a)
		2020*)	2020**)	2030**)	2020*)	2020**)	2030**)	2020/2030	2020*)	2020**)	2030**)	
ICE-small	60	3101	2098	1587				0.02	0.29	0.29	0.29	20
ICE-med	250	1690	1143	865				0.01	0.30	0.30	0.30	20
GT	1000	2147	2039	1932				0.01	0.22	0.22	0.22	20
MT-small	60	2412	2116	1410				0.02	0.25	0.28	0.31	10
MT-med	150	1964	1723	1148				0.02	0.26	0.29	0.33	10
FC-small	100	2715	4969	3605				0.03	0.36	0.40	0.46	10
FC-med	250	2176	3981	2889				0.03	0.36	0.40	0.46	10
ICE-HX-small	60				4080	2760	2088	0.02	0.29	0.29	0.29	20
ICE-HX-med	250				2485	1681	1271	0.01	0.30	0.30	0.30	20
GT-HX	1000				2941	2794	2647	0.01	0.22	0.22	0.22	20
MT-HX-small	60				2710	2377	1584	0.02	0.25	0.28	0.31	10
MT-HX-med	150				2207	1935	1290	0.02	0.26	0.29	0.33	10
FC-HX-small	100				3157	5778	4192	0.03	0.36	0.40	0.46	10
FC-HX-med	250				2530	4629	3359	0.03	0.36	0.40	0.46	10

*) projections based on estimates Annual Energy Outlook 2004

**) projections based on estimates Annual Energy Outlook 2009-2011

Abbreviations: ICE: natural gas fired internal combustion engine; GT: gas turbine; MT: micro turbine; FC: fuel cell; HX: heat exchanger for waste heat utilization

Another source for technology forecasts could be ICF, 2012. However, ICF, 2012 mostly looks into large industrial customers and neglects smaller units, which are the focus of this study.

13.10 Significant challenges and problems observed

None within this memorandum, but the challenges identified in the *"Collected Data Memorandum"* from January 2012 still exist:

- CEUS details for restaurants
  The biggest problem is still the limited CEUS database information, especially for the restaurant sector. For this project Berkeley Lab would need the hourly load profiles for all major restaurants considered/simulated with eQuest within CEUS.

  We kindly request these information to be released by CEC and ITRON to improve the quality of this project. For more information please look at "Collected Data Memorandum" from January 2012.

- Macro-grid CO_2 emissions
  We tried to contact Martha Brook from CEC who supposedly has a project with ICF on grid CO_2 emissions. This information is based on a phone call with Chris Scruton. However, so far we have not heard anything back from Martha Brook.

13.11 References

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13.12 Acronyms and abbreviations

AB 32	Assembly Bill 32 (the Global Warming Solutions Act)
CAA	Clean Air Act

Cal/EPA	California Environmental Protection Agency
CARB	California Air Resources Board
GHG	greenhouse gas
IOU	investor owned utility
MPR	market price referent
MRR	Mandatory Reporting Regulation (GHG reporting to US EPA and Cal/EPA for entities emitting over 25,000 mtCO_2e annually)
mtCO_2e	metric tons of CO_2 equivalent (emissions)
NERC	North American Electric Reliability Cooperation
PG&E	Pacific Gas and Electric
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
TOD	time of delivery
US EPA	United States Environmental Protection Agency

14 Appendix IV: Basic Results of DER-CAM Simulation Memorandum

Basic Results of DER-CAM Simulation Memorandum for task 2.8

Encouraging Combined Heat and Power in California Buildings

CEC 500-10-052, task 2.8

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14.1 Background

The goal of task 2.8 is to stimulate economic and environmentally sound natural gas-fired combined heat and power (CHP) and combined cooling, heating, and electric power (CCHP) adoption in California's medium sized *commercial building sector*.

Compared to other studies, this analysis will not be done in isolation and will consider other distributed energy resources (DER) technologies such as PV, solar thermal, electric and heat storage, which can be in competition with CHP and CCHP or supplement each other, depending on the building type and DER adoption strategy.

For this analysis the Distributed Energy Resources Customer Adoption Model (DER-CAM) from Lawrence Berkeley National Laboratory will be used. DER-CAM is a mixed-integer linear program (MILP) written and executed in the General Algebraic Modeling System (GAMS) (Stadler et al., 2010). Its objective is typically to minimize the annual costs or CO_2 emissions for providing energy services to the modeled site/building, including utility electricity and natural gas purchases, plus amortized capital and maintenance costs for any distributed generation (DG) investments. Other objectives, such as carbon or energy minimization, or a combination are also possible. The approach is fully technology-neutral and can include energy purchases, on-site conversion, both electrical and thermal on-site renewable harvesting, and end-use efficiency investments.

For more information on DER-CAM please refer to the "Collected Data Memorandum" from January 2012 and DER-CAM, 2012.

14.2 Aspects considered in this project

Berkeley lab will

- perform optimization runs for 2030 and update existing 2020 runs (Stadler et al., 2010)
- develop multiple scenarios that reflect grid de-carbonization, changes in equipment performance, and regulatory environment; besides CO_2 emissions also NOx emissions will be considered in the DER-CAM runs
- consider zero net energy buildings and their impact on CHP and CCHP
- consider different feed-in tariffs
- consider the impact of CO_2 pricing (e.g. cap-and-trade) on CHP/CCHP adoption

- put a special focus on the California restaurant sector since it is a major consumer of natural gas.

14.3 Data needed for the DER-CAM runs

To perform the described analysis with DER-CAM following data will be needed:

- hourly electricity, heating, cooling, domestic hot water, and cooking demand for the selected representative commercial buildings; the buildings will be selected from CEUS.
- electric and natural gas tariffs
- technology performance data and costs for the selected DER technologies
- CO_2 emissions of the macro-grid to assess the CO_2 mitigate potential of CHP and CCHP and other DER
- solar radiation for different locations in California to be able to consider the impact of PV and solar thermal on CHP/CCHP adoption.
- Energy Policies influencing the CHP/CCHP adoption, e.g. Self-Generation Incentive Program (SGIP)

Important influencing factors on the technology adoption in 2020 and 2030 are the technology performance as well as the regulation framework for the cap-and-trade system, possible Self-Generation Incentive Program (SGIP) in California and feed-in tariffs (see also SGIP Statistics, 2012).

14.4 Objective of this memorandum

Since this project will perform multiple scenarios for the different policy measures, which might impact the CHP/CCHP adoption a special focus was put on reliable base case scenarios, which consider:

- DER cost forecasts based on AEO forecasts (AEO, 2009; AEO, 2010; AEO, 2011) from the Forecasts and Scenarios Memorandum, February 2012
- natural gas price sensitivities
- 2030 marginal grid CO_2 emission forecasts and scenarios
- NOx treatment costs for internal combustion engines (ICE) systems

Almost 20 different runs with different assumptions for the electric tariffs, natural costs, marginal grid CO_2 emissions, and NOx treatment costs for ICE have been performed so far and 14 will be shown in this memorandum. A special focus on macro-grid de-carbonization and its impact on CHP/CCHP adoption in 2030 was put.

Please note that all results described in this memorandum are subject to updates/changes in course of the project. Task 2.8 started on Jan 1 2012 and the "Basic Results of DER-CAM Simulation Memorandum" is the third deliverable within this task.

14.5 Renewable energy targets

Previous work (Stadler et al., 2010) has shown that CHP and CCHP might be very attractive in terms of cost and CO_2 savings in 2020. However, that work neglects the impact of dramatic macro-grid de-carbonization due to more renewables. Figure 14-1 shows the planned targets for electricity and the generation mix in California until 2020. It shows significant changes within the forthcoming years. However, for this memorandum the year 2030 was used in the next chapters to estimate whether CHP and CCHP can prevail also in 2030.

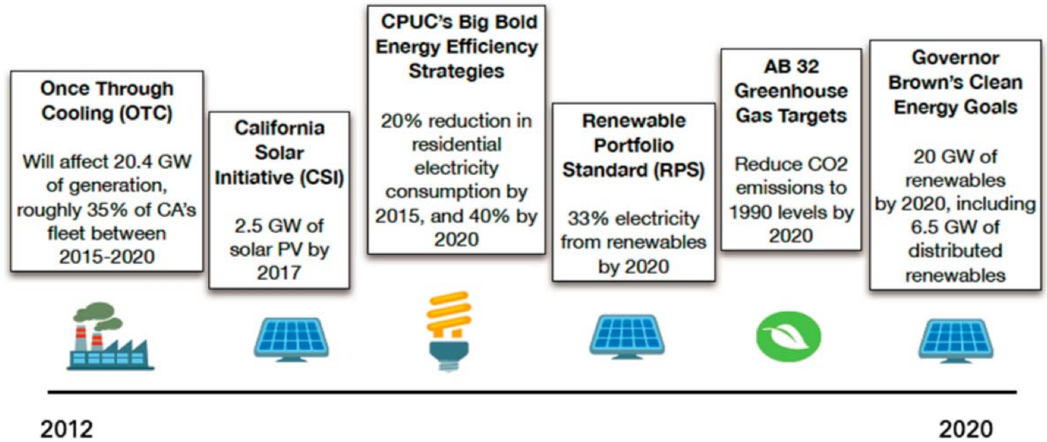

Figure 14-1. Renewable generation for California and RPS goals until 2020 (RMI, 2012)

14.6 Projected CO_2 emissions

Figure 14-2 shows the estimated carbon intensity for the macro-grid electricity in a reference and a deep GHG reduction scenario. For this project the reference scenario is used. In 2011 an average carbon intensity of about 88 gCO_2/MJ (~317 gCO_2/kWh_e) is given. For 2030 the reference scenario projects about 86 gCO_2/MJ (~309.6 gCO_2/kWh_e). A gas power plant, which is likely to be the marginal power plant, as it can change its output very fast, emits about 371 gCO_2/kWh_e (NREL, 2000). Therefore, the average of about 310 gCO_2/kWh_e considers also renewable capacities.

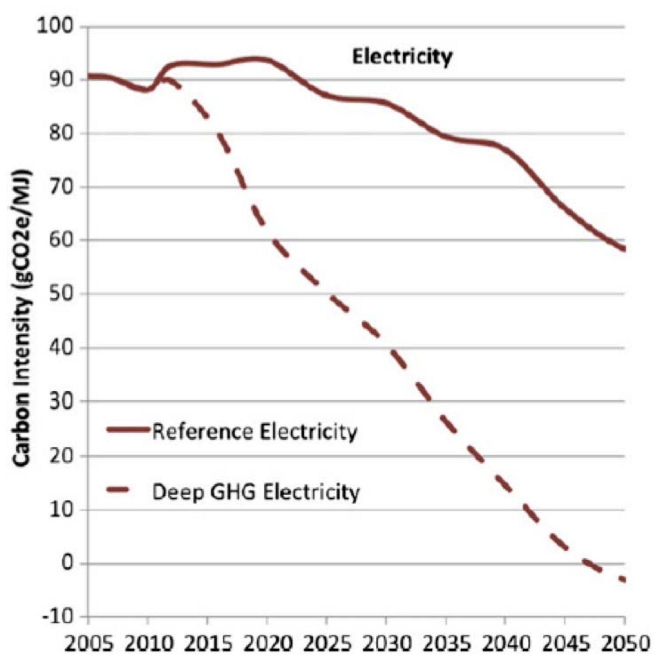

Figure 14-2. Comparison of average lifecycle carbon intensity (gCO_2/MJ HHV) for electricity in the reference and deep GHG reduction scenario (McCollum et al., 2011)

Based on Mahone et al., 2008 and E^3, 2009 the available hourly marginal CO_2 emissions with an average of about 510 gCO_2/kWh_e are given by Table 14-1 and Figure 14-3.

Table 14-1: Average hourly marginal CO_2 emissions from the Californian utilities in gCO_2/kWh (E[3], 2009)

* Hourly Marginal CO_2 Emissions (gCO_2/kWh)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	482	481	494	486	485	509	525	517	507	498	504	504	509	492	511	525	521	512	507	488	519	510	498	474
February	505	522	508	531	516	506	507	529	510	504	493	486	490	501	497	496	528	540	515	507	495	498	492	489
March	505	556	558	548	529	520	500	501	486	484	475	482	482	487	494	495	488	499	491	484	485	488	491	514
April	524	547	616	605	560	503	532	509	508	502	503	507	499	506	507	480	518	517	487	581	541	508	516	506
May	531	564	580	565	545	496	522	513	500	486	483	491	481	482	497	518	534	484	493	527	497	482	499	512
June	500	485	540	539	429	493	513	510	460	484	496	470	502	515	514	520	557	508	494	468	502	501	467	477
July	483	497	484	490	505	493	493	511	518	518	516	539	557	515	482	453	525	530	529	533	523	512	489	478
August	520	512	520	518	534	518	513	491	505	519	536	541	532	544	511	542	516	528	545	564	532	511	511	527
September	511	481	493	512	486	533	507	517	527	519	518	541	541	511	543	491	528	545	549	543	540	536	502	514
October	489	496	501	507	517	502	530	530	513	505	515	510	523	509	510	513	528	522	523	519	499	489	495	492
November	504	499	503	514	502	493	521	502	523	509	510	503	516	511	516	512	523	519	504	505	512	504	492	489
December	487	507	506	502	517	501	523	508	518	504	497	506	522	511	511	527	532	527	518	506	504	495	507	486

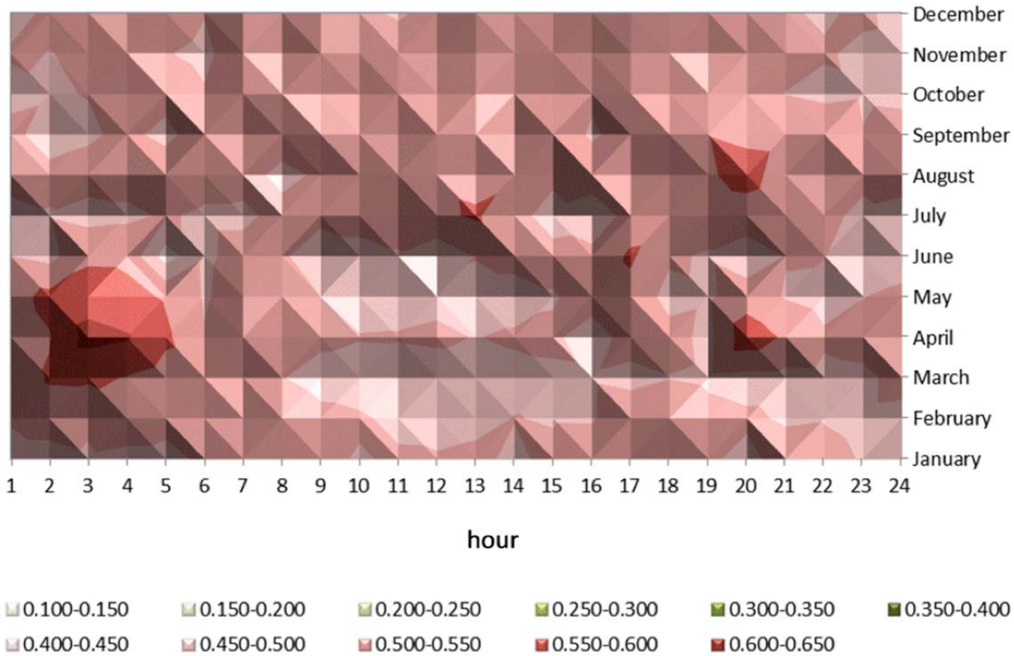

Figure 14-3. Average hourly marginal CO_2 emissions from the Californian utilities in $kgCO_2/kWh$ (E[3], 2009)

With McCollum et al. (2011) the hourly CO_2 emissions for 2030 can be estimated. The results are given in Table 14-2 and Figure 14-4. The new calculated 2030 hourly CO_2 emissions are about 40% below the E[3] 2009 estimates from Table 14-1. E[3], 2010 provides updated data for 2020 and these data will be considered in future runs and compared to the assumptions made in this project.

Table 14-2: Average hourly marginal CO_2 emissions from the Californian utilities in 2030 in gCO_2/kWh (LBNL calculations, McCollum et al., 2011 E[3], 2009)

* Hourly Marginal CO_2 Emissions - 2030 (gCO_2/kWh)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	292	292	300	295	294	309	319	313	308	302	306	306	309	299	310	319	316	311	307	296	315	309	302	287
February	306	317	308	322	313	307	308	321	309	306	299	295	297	304	301	301	320	327	313	308	300	302	298	296
March	307	337	338	332	321	316	304	304	295	294	288	293	293	295	299	301	296	303	298	294	294	296	298	312
April	318	332	374	367	340	305	323	309	308	304	305	307	303	307	308	291	314	314	296	352	328	308	313	307
May	322	342	352	343	330	301	317	312	303	295	293	298	292	292	301	314	324	293	299	320	301	293	303	310
June	304	294	327	327	260	299	311	309	279	294	301	285	305	312	312	315	338	308	300	284	305	304	283	289
July	293	301	293	298	306	299	299	310	314	314	313	327	338	312	292	275	319	322	321	324	317	310	297	290
August	315	310	316	315	324	314	311	298	307	315	325	328	323	330	310	329	313	321	331	342	323	310	310	320
September	310	292	299	311	295	323	307	314	320	315	314	328	328	310	330	298	320	330	333	329	328	325	304	312
October	297	301	304	307	313	305	321	321	312	306	313	310	317	309	309	311	321	316	317	315	303	297	300	298
November	306	303	305	312	304	299	316	305	317	309	310	305	313	310	313	311	318	315	306	306	310	306	299	297
December	295	308	307	305	313	304	317	308	314	306	302	307	317	310	310	319	323	320	314	307	306	300	308	295

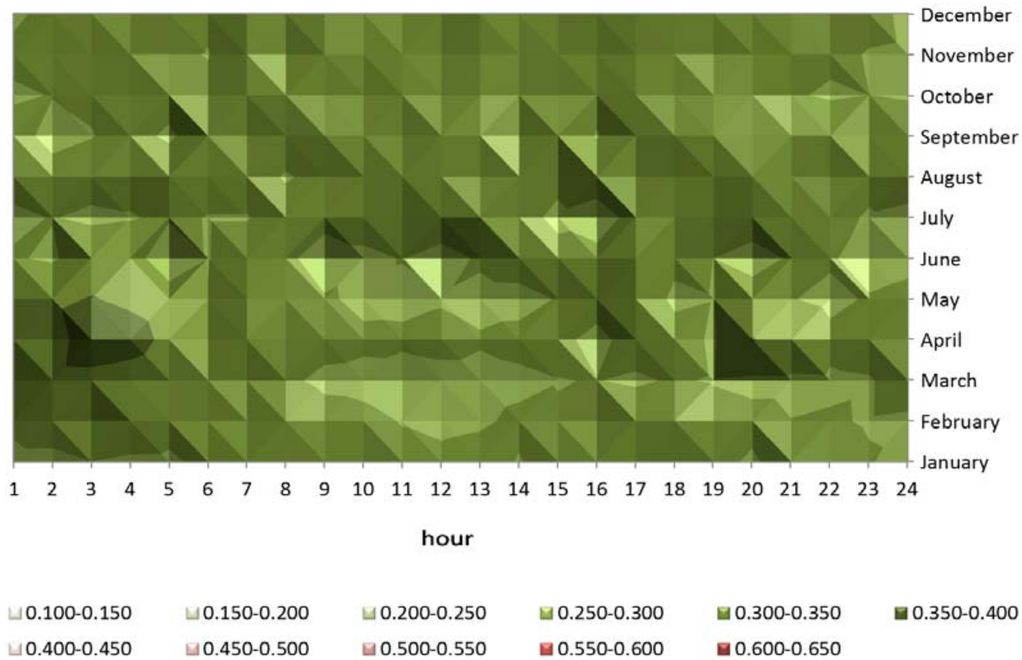

Figure 14-4. Average hourly marginal CO_2 emissions from the Californian utilities in 2030 in $kgCO_2$/kWh (LBNL calculations, McCollum et al., 2011 E[3], 2009)

14.7 Basic electric and natural gas tariff details used for the 2030 runs

The tables below summarize the electric and natural gas rates used in the basic DER-CAM optimization runs.

Table 14-3: Electric tariffs per utility (based on PG&E, SCE, SDG&E tariff information, see also Collected Data Memorandum for task 2.8 from January 2012)

building size	< 200 kW_{peak}	≥ 200 & < 500 kW_{peak}	≥ 500 & < 1000 kW_{peak}	≥ 1000 kW_{peak}
internal DER-CAM abbreviation	E1	E2	E3	E4

PG&E	A-1 flatrate	A-10A non-TOU, demand metered, secondary voltage	E-19 TOU, secondary voltage	E-20 TOU, secondary voltage
SCE	GS-2 flatrate	TOU-GS-3, option B	TOU-8-CPP, option B*	
SDG&E	AL-TOU secondary		AL-TOU secondary	

*Please note that CPP events are not considered in the basic runs.

Table 14-4: Monthly fee for electricity ($/month) in 2012US$ (based on PG&E, SCE, SDG&E tariff information, see also Collected Data Memorandum for task 2.8 from January 2012)

building size	< 200 kW_{peak}	≥ 200 & < 500 kW_{peak}	≥ 500 & < 1000 kW_{peak}	≥ 1000 kW_{peak}
internal DER-CAM abbreviation	E1	E2	E3	E4
PG&E	9.99	169.88	769.47	1029.30
SCE	134.17	472.44	577.22	
SDG&E	58.22		232.87	

Table 14-5: Monthly demand rates for electricity ($/kW month) per utility in 2012US$ (based on PG&E, SCE, SDG&E tariff information, see also Collected Data Memorandum for task 2.8 from January 2012)

utility		season	non coincident	on peak	mid peak	off peak
PG&E	E1	Winter				
		Summer				
	E2	Winter		5.63	5.63	5.63
		Summer		12.15	12.15	12.15
	E3	Winter	11.85		0.21	
		Summer	11.85	14.70	3.43	
	E4	Winter	11.72		0.23	
		Summer	11.72	14.32	3.15	
SCE	E1	Winter	12.04			
		Summer	12.04	16.49	16.49	16.49
	E2	Winter	13.13			
		Summer	13.13	12.73	2.85	
	E3/E4	Winter	12.66			
		Summer	12.66	16.08	4.53	
SDG&E	E1/E2	Winter	13.57	4.92		
		Summer	13.57	12.86		
	E3/E4	Winter	13.57	4.92		
		Summer	13.57	12.86		

able 14-6: Electricity rates ($/kWh) per utility in 2012US$ (based on PG&E, SCE, SDG&E tariff information, see also Collected Data Memorandum for task 2.8 from January 2012)

utility		season	on peak	mid peak	off peak
PG&E	E1	Winter	0.14493	0.14493	0.14493
		Summer	0.20522	0.20522	0.20522
	E2	Winter	0.10331	0.10331	0.10331
		Summer	0.13884	0.13884	0.13884
	E3	Winter		0.09063	0.07320
		Summer	0.13476	0.09579	0.07028
	E4	Winter		0.08765	0.07066
		Summer	0.12421	0.09141	0.06979
SCE	E1	Winter	0.06526	0.06526	0.06526
		Summer	0.08167	0.08167	0.08167
	E2	Winter		0.06256	0.04681
		Summer	0.11717	0.08355	0.05812
	E3/E4	Winter		0.07779	0.05278
		Summer	0.13990	0.08850	0.05629
SDG&E	E1/E2	Winter	0.13456	0.12627	0.10611
		Summer	0.14043	0.12115	0.10078
	E3/E4	Winter	0.13456	0.12627	0.10611
		Summer	0.14043	0.12115	0.10078

The tables above are used for run sets 1-3 (see next chapter).

Table 14-7: Basic fuel Prices ($/kWh$_t$) in 2012US$ (based on PG&E, SoCalGas, SDG&E tariff information)

utility	season	natural gas price
PG&E	Winter	0.02032
	Summer	0.01864
SCE	Winter	0.01678
	Summer	0.01678
SDG&E	Winter	0.01780
	Summer	0.01780

Table 14-8: Higher fuel prices ($/kWh$_t$) in 2012US$ (based on PG&E, SoCalGas, SDG&E tariff information)

utility	season	natural gas price
PG&E	Winter	0.026059
	Summer	0.023668
SCE	Winter	0.027944
	Summer	0.027944
SDG&E	Winter	0.021135
	Summer	0.021135

Run set 1 uses Table 14-7 and all other runs use Table 14-8 as input data. For the definition of the run sets please refer to the next section.

Table 14-9: Monthly demand rates for electricity ($/kW month) on transmission level per utility for customers above 1 MW_p electricity demand in 2012US$ (based on PG&E, SCE, SDG&E tariff information, see also Collected Data Memorandum for task 2.8 from January 2012)

utility		season	non coincident	on peak	mid peak	off peak
PG&E	E4	Winter	4.06			
		Summer	4.06	12.24	2.65	
SCE	E3/E4	Winter	11.88			
		Summer	11.88	19.49	5.46	
SDG&E	E3/E4	Winter	5.64	0.58		
		Summer	5.64	7.01		

Table 14-10: Electricity rates ($/kWh) on transmission level per utility for customers above 1 MW_p electricity demand) in 2012US$ (based on PG&E, SCE, SDG&E tariff information)

utility		season	on peak	mid peak	off peak
PG&E	E4	Winter		0.07680	0.06704
		Summer	0.08981	0.07574	0.06397
SCE	E3/E4	Winter		0.07505	0.04980
		Summer	0.10323	0.08078	0.05407
SDG&E	E3/E4	Winter	0.13446	0.12723	0.10808
		Summer	0.13972	0.12227	0.10293

Table 14-9 and Table 14-10 are used for the run set 4 in the next chapter.

14.8 Results

DER-CAM was reprogrammed within this project so that it can handle FiT and the SGIP program. Results for FiT (sales) will be shown in this memorandum.

For all available scenarios the CEUS database provides the load profiles for 138 buildings above 100kW electric peak load (see Table 14-11 and “Collected Data Memorandum” from Jan 2012).

Table 14-11: Used building profiles above 100 kW_e peak load (CEUS, 2006)

Utility		PG&E				SCE				SDGE	
Category	Size	FCZ 01	FCZ 03	FCZ 04	FCZ 05	FCZ 07	FCZ 08	FCZ 09	FCZ 10	FCZ 13	
LODG	S	-	-	-	-	-	-	-	-	-	-
	M	-	1	1	1	-	1	1	1	1	7
	L	1	1	1	1	1	1	1	1	1	9
SOFF	S	-	-	-	-	-	-	-	-	-	-
	M	-	-	-	-	-	-	-	-	-	-
	L	-	-	1	-	-	-	-	-	-	1
WRHS	S	-	-	-	-	-	-	-	-	-	-
	M	-	-	-	-	-	-	-	-	-	-
	L	-	1	1	1	-	1	1	1	1	7
SCHL	S	-	-	-	-	-	-	-	-	-	-
	M	1	1	1	1	1	1	1	1	1	9
	L	1	1	1	1	1	1	1	1	1	9
RETL	S	-	-	-	-	-	-	-	-	-	-
	M	-	-	-	-	-	-	-	-	-	-
	L	1	1	1	1	1	1	1	1	1	9
REST	S	-	-	-	-	-	-	-	-	-	-
	M	-	-	-	-	-	-	-	-	-	-
	L	-	-	1	-	-	-	-	-	-	1
REFW	S	-	-	-	-	-	-	-	-	-	-
	M	1	1	1	1	1	1	1	1	1	9
	L	-	1	1	1	1	1	1	1	1	8
LOFF	S	1	1	1	1	1	1	1	1	1	9
	M	1	1	1	1	1	1	1	1	1	9
	L	-	1	1	1	1	1	-	1	1	7
HLTH	S	-	-	-	-	-	-	-	-	-	-
	M	1	1	1	-	1	1	1	1	1	8
	L	1	1	1	1	1	1	1	1	1	9
GROC	S	-	-	-	-	-	-	-	-	-	-
	M	-	-	-	-	-	-	-	-	-	-
	L	1	1	1	1	1	1	1	1	1	9
COLL	S	-	-	-	-	-	-	-	-	-	-
	M	1	1	1	1	1	1	1	1	1	9
	L	1	1	1	1	1	1	1	1	1	9
Sum per Utility		61				61				16	138
Total Sum		12	16	18	15	14	16	15	16	16	

LODG: lodging and hotels. SOFF: small office buildings (<30 000 sqft), WRHS: warehouses, SCHL: schools, RETL: retail, REST: restaurants, REFW: refrigerated warehouses, LOFF: large office (>30 000 sqft), HLTH: healthcare, GROC: food / liquor, COLL: Colleges and Universities

PG&E service territory: climate zone FCZ01-FCZ05; SCE service territory: climate zone FCZ07-FCZ10; SDG&E service territory: climate zone FCZ13

Table 14-12 shows the scenarios / base cases which have been performed so far.

Table 14-12: Short descriptions of all performed runs and the underlying details

runs	description
run set (1)	based on the information provided in Table 14-1, Table 14-3 to Table 14-7
run set (2)	run set (2) is equal to run set (1) except the higher NG prices (Table 14-8 instead of Table 14-7 is used)
run set (3)	run set (3) is equal to run set (2) except the lower marginal CO_2 emissions (Table 14-2 instead of Table 14-1 is used)

run set (4)	run set (4) is equal to run set (3) except the introduction of NOx treatment costs (300 $/kW, based on ICF, 2012) for ICE systems and electric tariffs based on transmission levels/high distribution level for customers above 1000 kW peak demand (Table 14-9, Table 14-10 instead of Table 14-5 to able 14-6)

The most realistic run set (4) results, from the authors' perspective, are shown in Table 14-13. This run set assumes:

1. Berkeley Lab price forecast based on AEO reports (see Task2.8 Forecasts and Scenarios Memo from 02/28/2012)
2. higher natural gas prices (Table 14-8 instead of Table 14-7)
3. low macro-grid CO_2 emissions (see chapter 14.6, Table 14-2)
4. use of NOx treatment costs for ICE systems (ICF, 2012)
5. lower electricity prices for customers above 1000 kW_e peak demand.

Run 4a is the base case run, where no CHP / CCHP nor any other DER is allowed and all energy needs to be purchased from the local utility. Run 4c[18] represents full cost minimization results with higher CO_2 emissions as within the base case. Due to the low macro-grid CO_2 emissions in 2030, based on Table 14-2, it is very difficult to reduce the CO_2 emissions. Run 4c clearly shows that CHP is a cost measure and the 2.5GW of adopted CHP can reduce the costs, compared to the base case, for the considered commercial buildings by 15%.

Run 4e, the pure CO_2 minimization case, reduces the annual energy costs by 3.6% and the CO_2 emissions by 4.4%. This CO_2 emission case assumes that no building can have annual energy costs, which are above the base case costs and this assumption results in reduced PV capacities and increased solar thermal capacities, compared to full cost minimization (run 4c). The cost constraint forces cheaper solutions as solar thermal and increases the usage of the CHP systems and the capacity factor increases from 60.5% to 66.9%. The very expensive absorption cooling technologies are eliminated in run 4e (cooling offset is zero in Table 14-13).

However, as can be seen from Table 14-13, the CHP capacity decreases dramatically to 0.7GW.

Possible FiT tariffs for CHP and PV slightly increase the CHP capacity in Run 4c2 and Run 4e2 and use absorption cooling.

[18] Run 4b and run 4d are not shown in the tables and represent the 2020 optimization.

Table 14-13: 2030 result summary of run set 4 for the considered commercial buildings (source: DER-CAM runs)

run	4a	4c	4c2	4e	4e2
run description:	base case	2030 (min US$)	2030 (min US$) + sales	2030 (min CO_2)	2030 (min CO_2) + sales
annual energy costs (bln $)	5.3	4.5	4.3	5.1	5.1
annual energy costs (%)	100.0	85.0	81.3	96.4	96.2
change in annual energy costs (%)		(15.0)	(18.7)	(3.6)	(3.8)
annual marginal CO_2 emissions (Mt/a)	14.5	15.7	16.4	13.8	13.8
annual marginal CO2 emissions (%)	100.0	108.4	113.2	95.6	95.4
change in annual marginal CO_2 emssions (%)		8.4	13.2	(4.4)	(4.6)
installed DG capacities (MW)		2,528.5	3,043.8	695.4	787.7
installed PV capacities (MW)		496.8	979.4	147.0	134.9
installed Solar Thermal capacities (MW)		18.8	7.0	472.7	494.2
electricity produced by DG (without PV) (GWh)		13,402.4	15,802.1	4,073.9	4,524.0
PV and DG sales (GWh)		-	1,713.1	-	1.3
cooling offset (GWh)		1,031.0	1,112.3	-	13.9
building linked mobile storage (GWh)		-	-	-	-
stationary storage (GWh)		97.6	138.2	44.8	207.7
DG capacity factor (%)		60.5	59.3	66.9	65.6

Table 14-14: Installed capacities for run set 4 for the considered commercial buildings (source: DER-CAM runs)

run	4a	4c	4c2	4e	4e2
installed DG capacity (MW)	base case	2030 (min US$)	2030 (min US$) + sales	2030 (min CO2)	2030 (min CO2) + sales
total installed DG capacity (MW)	-	2,528.5	3,043.8	695.4	787.7
ICE	-	317.3	840.1	-	-
ICE-HX	-	858.4	132.6	-	-
GT	-	-	-	-	-
GT-HX	-	-	-	-	-
MT	-	63.4	103.4	-	-
MT-HX	-	1,289.5	1,967.6	656.7	752.2
FC	-	-	-	-	-
FC-HX	-	-	-	38.8	35.5
% ICE of DG	-	46.5	32.0	-	-
% GT of DG	-	-	-	-	-
% MT of DG	-	53.5	68.0	94.4	95.5
% FC of DG	-	-	-	5.6	4.5

Within the cost minimization (run 4c) almost half of the installed systems are internal combustion engines (ICE) and the other half are micro turbines (MT). Within the CO_2 minimization about 5% are fuel cells (FC) and the rest are MTs as these are the systems with the highest expected efficiency rate compared to the investment costs. Please note that the cost minimization case adopts ICEs and MTs without any heat exchanger (HX) and no waste heat utilization takes place and this also drives the high CO_2 emissions in run 4c. In run 4e (CO_2 minimization) all technologies use waste heat for heating and domestic hot water and this improves the CO_2 balance.

Table 14-15: Installed units for run set 4 for the considered commercial buildings (source: DER-CAM runs)

run	4a	4c	4c2	4e	4e2
installed units (pieces)	base case	2030 (min US$)	2030 (min US$) + sales	2030 (min CO2)	2030 (min CO2) + sales
total number of installed DG units (pieces)	-	16,460	21,201	10,045	11,596
ICE	-	1,269	3,625	-	-
ICE-HX	-	3,698	703	-	-
GT	-	-	-	-	-
GT-HX	-	-	-	-	-
MT	-	675	1,227	-	-
MT-HX	-	10,818	15,646	9,890	11,454
FC	-	-	-	-	-
FC-HX	-	-	-	155	142
% ICE of DG	-	30.2	20.4	-	-
% GT of DG	-	-	-	-	-
% MT of DG	-	69.8	79.6	98.5	98.8
% FC of DG	-	-	-	1.5	1.2

The remaining run sets (1) – (3) are shown in the following tables. For all runs a base case (run a), a cost minimization (run c) and a CO_2 minimization (run e) was performed.

Table 14-16: Summary run set (1) (source: DER-CAM runs)[19]

run	1a	1c	1e
run description:	base case	min US$	min CO_2
annual energy costs (bln $)	5.4	3.5	3.9
annual energy costs (%)	100.0	63.8	72.7
change in annual energy costs (%)		- 36.2	- 27.3
annual marginal CO2 emissions (Mt/a)	21.8	19.5	16.4
annual marginal CO2 emissions (%)	100.0	89.4	75.2
change in annual marginal CO2 emssions (%)		- 10.6	- 24.8
installed DG capacities (MW)		5,379.3	4,314.9
installed PV capacities (MW)		901.2	1,260.5
installed Solar Thermal capacities (MW)		-	328.9
electricity produced by DG (without PV) (GWh)		26,609.8	24,097.7
cooling offset (GWh)		2,558.2	2,338.6
building linked mobile storage (GWh)		-	-
stationary storage (GWh)		63.0	100.1
DG capacity factor (%)		56.5	63.8

[19] Please note that Stadler et al., 2010 does not consider natural gas only loads, .i.e. cooking, and therefore, this study reports slightly higher CO_2 emissions for the base case.

Table 14-17: Summary run set (2) (source: DER-CAM runs)

run	2a	2c	2e
run description:	base case	min US$	min CO_2
annual energy costs (bln $)	5.6	4.3	4.6
annual energy costs (%)	100.0	77.2	83.0
change in annual energy costs (%)		- 22.8	- 17.0
annual marginal CO2 emissions (Mt/a)	21.8	19.9	18.1
annual marginal CO2 emissions (%)	100.0	91.4	83.2
change in annual marginal CO2 emssions (%)		- 8.6	- 16.8
installed DG capacities (MW)		3,893.7	3,056.4
installed PV capacities (MW)		617.0	795.8
installed Solar Thermal capacities (MW)		18.4	195.7
electricity produced by DG (without PV) (GWh)		17,723.3	17,326.1
cooling offset (GWh)		1,670.9	1,564.6
building linked mobile storage (GWh)		-	-
stationary storage (GWh)		36.5	514.3
DG capacity factor (%)		52.0	64.7

Table 14-18: Summary run set (3) (source: DER-CAM runs)

run	3a	3c	3e
run description:	base case	min US$	min CO_2
annual energy costs (bln $)	5.6	4.3	5.3
annual energy costs (%)	100.0	77.0	94.7
change in annual energy costs (%)		- 23.0	- 5.3
annual marginal CO2 emissions (Mt/a)	14.5	16.7	13.7
annual marginal CO2 emissions (%)	100.0	115.7	94.6
change in annual marginal CO2 emssions (%)		15.7	- 5.4
installed DG capacities (MW)		3,879.4	799.7
installed PV capacities (MW)		658.7	313.5
installed Solar Thermal capacities (MW)		20.6	427.6
electricity produced by DG (without PV) (GWh)		17,769.9	4,594.2
cooling offset (GWh)		1,652.0	19.9
building linked mobile storage (GWh)		-	-
stationary storage (GWh)		73.1	49.9
DG capacity factor (%)		52.3	65.6

Table 14-19: Summary run set (1) - run set (3), used technologies (source: DER-CAM runs)

	run	1a	1c	1e	2a	2c	2e	3a	3c	3e
installed DG Capacity (MW)		base case	min US$	min CO_2	Base Case	min US$	min CO_2	Base Case	min US$	min CO_2
total	(MW)	-	5,379.3	4,314.9	-	3,887.5	3,026.9	-	3,838.2	795.6
ICE		-	1,405.0	-	-	994.9	-	-	943.7	-
ICE-HX		-	3,361.1	-	-	2,465.4	-	-	2,464.4	-
GT		-	-	-	-	-	-	-	-	-
GT-HX		-	-	-	-	-	-	-	-	-
MT		-	11.6	15.2	-	-	5.9	-	-	-
MT-HX		-	601.7	3,589.4	-	427.3	2,570.0	-	430.1	688.4
FC		-	-	-	-	-	103.3	-	-	-
FC-HX		-	-	710.3	-	-	347.8	-	-	107.3
% ICE of DG		-	88.6	-	-	89.0	-	-	88.8	-
% GT of DG		-	-	-	-	-	-	-	-	-
% MT of DG		-	11.4	83.5	-	11.0	85.1	-	11.2	86.5
% FC of DG		-	-	16.5	-	-	14.9	-	-	13.5

Increased natural gas prices from run set (1) to run set (2) reduce the installed DG/CHP capacity. The current low natural gas prices seem to be very unrealistic for 2030, and therefore, it was decided to use the higher natural gas prices from Table 14-8, which are comparable to ICF, 2012.

Assuming CO_2 minimization, run 2e delivers the upper boundary for DG/CHP adoption with roughly 3 GW in 2030. The reduced marginal macro-grid CO_2 emissions in run set (3) and (4) do not really reduce the installed DG/CHP capacity as long as cost minimization is considered. In the case of CO_2 minimization the installed natural gas fired engines are reduced to 0.7 GW, which delivers the lower boundary for DG/CHP adoption. Depending on the de-carbonization of the utilities, DG/CHP has an adoption potential between 3 GW and 0.7 GW by 2030[20].

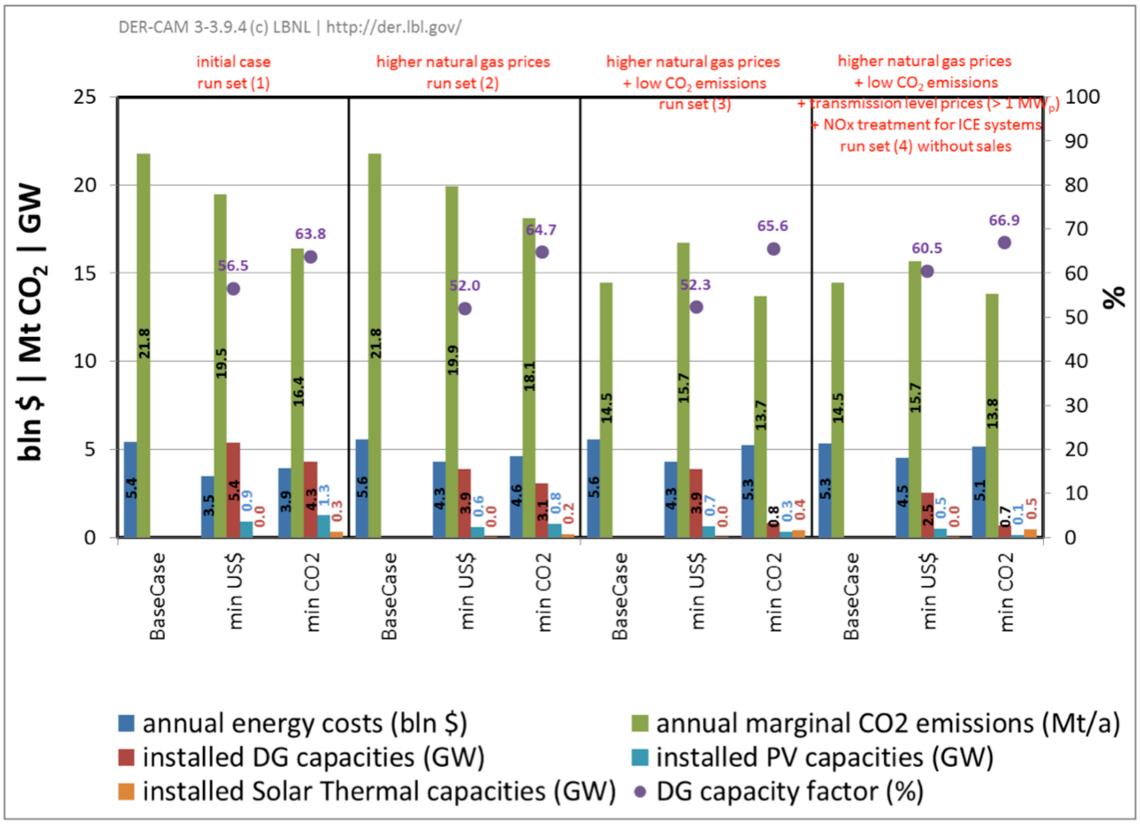

Figure 14-5. Result summary for all run sets for the considered commercial buildings (source: DER-CAM runs)

Very interesting is the PV and solar thermal adoption in the CO_2 minimization cases. For the run sets (1) and (2) PV and solar thermal capacity always increases, compared to cost minimization. However, with reduced marginal macro-grid CO_2 emissions and the cost constraint for CO_2 minimization this behavior flips and always favors the cheaper solar thermal systems (compare run 3c with run 3e and 4c with 4e). PV decreases and the cheaper solar thermal systems are favored since the cost constraint forces base case case for every building. This reduction in PV capacity is in contrast to the CSI goals of 2.5 GW PV by 2017. Please note that this work only reports on commercial buildings in California, which constitute roughly 35% of the commercial sector electricity demand (Stadler et al., 2010). This behavior will be further investigated in the future.

Finally, please note that the best average DG/CHP capacity factor, which is calculated by DER-CAM, does not exceed 67% and this is also in contrast to the frequently discussed 80%.

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[20] Please note that this is based on the current building stock and building stock growth can be considered in future work.

14.9 Significant challenges and problems observed

None within this memorandum, but some of the challenges identified in the *"Collected Data Memorandum"* from January 2012 still exist*:*

- CEUS details for restaurants
  The biggest problem is still the limited CEUS database information, especially for the restaurant sector. For this project Berkeley Lab would need the hourly load profiles for all major restaurants considered/simulated with eQuest within CEUS.

  We kindly request these information to be released by CEC and ITRON to improve the quality of this project. For more information please look at "Collected Data Memorandum" from January 2012.

- macro-grid CO_2 emissions
  Compared to the previous two memorandums this problem can be considered as almost solved since we were able to estimate the macro-grid CO_2 emissions based on the following publications:

  1. McCollum, D., Yang, C., Yeh, S., Ogden, J., 2011: "Deep greenhouse gas reduction scenarios for California - Strategic implications from the CA-TIMES energy-economic systems model," Energy Strategy Reviews, 1/1, pp.19-32, http://dx.doi.org/10.1016/j.esr.2011.12.003, May 2012
  2. E^3 Energy+Envirnomental Economics, 2009, GHG Tool for Buildings in California April 09 v. 2 http://www.ethree.com/public_projects/ghg.php
  3. Mahone, A., S. Price, W. Morrow, 2008, "Developing a Greenhouse Gas Tool for Buildings in California: Methodology and Use," Energy and Environmental Economics, Inc., September 10, 2008 and PLEXOS Production Simulation Dispatch Model.

14.10 References

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ICF, 2012, "Combined Heat and Power: Policy Analysis and 2011 – 2030 Market Assessment," ICF International, Inc., prepared for the California Energy Commission, CEC-200-2012-002, February 2012

Mahone, A., S. Price, W. Morrow, 2008, "Developing a Greenhouse Gas Tool for Buildings in California: Methodology and Use," Energy and Environmental Economics, Inc., September 10, 2008 and PLEXOS Production Simulation Dispatch Model

McCollum, D., Yang, C., Yeh, S., Ogden, J., 2011: "Deep greenhouse gas reduction scenarios for

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NREL, 2000, "Life Cycle Assessment of a Natural Gas Combined-Cycle Power Generation System," http://www.nrel.gov/docs/fy00osti/27715.pdf

RMI, 2012: http://www.rmi.org/Content/Files/RMI_ZNE_Presentation_120306.pdf, May 2012.

SGIP Statistics, 2012, downloaded from Pacific Gas and Electric, http://www.pge.com/sgip/

Stadler M., Marnay C., Cardoso G., Lipman T., Mégel O., Ganguly S., Siddiqui A., Lai J. ,2010, "The CO2 abatement potential of California's mid-sized commercial buildings," Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-3024E. Available at: http://eetd.lbl.gov/EA/EMP/emp-pubs.html

14.11 Acronyms and abbreviations

$/kWh$_t$	US Dollars per kWh thermal
bln $	billion US Dollars
DER-CAM	Distributed Energy Resources Customer Adoption Model
gCO_2/kWh_e	grams of CO_2 per kWh electricity, 1 gram = 1/1000 kg
GHG	greenhouse gas
GW	Giga Watt = 10^9 Watt
$kgCO_2/kWh$	kilogram CO_2 per kWh
kt/a	1000 metric tons of CO_2 per year
kW_e	kW electricity
mln $	million US Dollars
Mt/a	metric tons of CO_2 per year
MW	Mega Watt = 10^6 Watt
PG&E	Pacific Gas and Electric
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SoCalGas	Southern California Gas Company

15 Appendix V: Site Analyses and Restaurant Analysis Memorandum

Side Analyses and Restaurant Analysis Memorandum for task 2.8

Encouraging Combined Heat and Power in California Buildings

CEC 500-10-052, task 2.8

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15.1 Background

The goal of task 2.8 is to stimulate economic and environmentally sound natural gas-fired combined heat and power (CHP) and combined cooling, heating, and electric power (CCHP) adoption in California's medium sized *commercial building sector*.

Compared to other studies, this analysis will not be done in isolation and will consider other distributed energy resources (DER) technologies such as PV, solar thermal, electric and heat storage, which can be in competition with CHP and CCHP or supplement each other, depending on the building type and DER adoption strategy.

For this analysis the Distributed Energy Resources Customer Adoption Model (DER-CAM) from Lawrence Berkeley National Laboratory will be used. DER-CAM is a mixed-integer linear program (MILP) written and executed in the General Algebraic Modeling System (GAMS) (Stadler et al., 2010). Its objective is typically to minimize the annual costs or CO_2 emissions for providing energy services to the modeled site/building, including utility electricity and natural gas purchases, plus amortized capital and maintenance costs for any distributed generation (DG) investments. Other objectives, such as carbon or energy minimization, or a combination are also possible. The approach is fully technology-neutral and can include energy purchases, on-site conversion, both electrical and thermal on-site renewable harvesting, and end-use efficiency investments.

For more information on DER-CAM please refer to the "Collected Data Memorandum" from January 2012 and DER-CAM, 2012.

15.2 Aspects considered in this project

Berkeley lab will

- perform optimization runs for 2030 and update existing 2020 runs (Stadler et al., 2010)
- develop multiple scenarios that reflect grid de-carbonization, changes in equipment performance, and regulatory environment; besides CO_2 emissions also NOx emissions will be considered in the DER-CAM runs
- consider zero net energy buildings and their impact on CHP and CCHP
- consider feed-in tariffs
- consider the impact of CO_2 pricing (e.g. cap-and-trade) on CHP / CCHP adoption

- put a special focus on the California restaurant sector since it is a major consumer of natural gas.

15.3 Objective of this memorandum

The objective of this memorandum is to show 2030 DER-CAM optimization results for

- zero net energy buildings and the impact on DER as well as CHP / CHP adoption
- sensitivity runs on better performance for fuel cells, i.e. increased lifetime of fuel cells and how this will impact the CHP and CCHP adoption
- the restaurant sector.

Almost 40 different run sets (equal to more than 5500 individual optimization runs) with different assumptions for the tariffs, natural costs, marginal grid CO_2 emissions, and NOx treatment costs for ICE, and fuel cell lifetime have been performed so far in this project and this memorandum just focuses on the latest run sets specified and performed since the last memorandum in May 2012.

Please note that all results described in this memorandum are subject to updates/changes in course of the project.

15.4 Overview optimization results

The most realistic run set (4) for 2030 (see Basic Results of DER-CAM Simulation Memo from May 2012), from the authors' perspective, was extended for this memorandum and is shown in Table 15-1. All runs in run set (4) assume:

- Berkeley Lab price forecast based on AEO reports (AEO, 2009; AEO, 2010; AEO, 2011)
- realistic higher natural gas prices (Table 8 from Basic Results of DER-CAM Optimization Memo)
- grid de-carbonization and low macro-grid CO_2 emissions (Table 2 from Basic Results of DER-CAM Simulation Memo)
- use of NOx treatment costs for ICE systems (ICF, 2012)
- realistic low electricity prices for customers above 1000 kW_e peak demand (Table 9 and Table 10 from Basic Results of DER-CAM Simulation Memo).

Table 15-1 shows the different settings for the performed runs within run set (4), which are important for this memorandum.

Table 15-1: Short descriptions of the underlying details for available optimization runs within run set (4) [21]

run set	description
(4a1)	base case for the run set (4) without any DER units (all energy needs to be purchased from the utility); this is exactly run 4a from the Basic Results of DER-CAM Simulation Memo
(4c3)	cost minimization strategy and zero net energy buildings (ZNEB) constraint forcing the buildings to be balanced on energy purchase and sales; the ZNEB constraint is based on natural gas equivalents; ZNEB runs require feed-in tariffs (FiT) to be turned on within DER-CAM to allow sales and the fulfillment of the ZNEB constraint; CHP and PV sales are allowed
(4e3)	carbon minimizing strategy and increased lifetime of fuel cells (from 10 to 20 years); this run can be directly compared to 4e from the Basic Results of DER-CAM Simulation Memorandum from May 2012; a fuel cell constraint is applied that forces fuel cells to run 24 hours a day (if attractive) with minimal variability; this behavior is similar to a SOFC
(4e4)	equal to run set (4e3) except that fuel cells have no runtime restrictions and can follow the load; this behavior is very similar to a PEMFC
(4e5)[22]	carbon minimization of run set (4e3) plus the ZNEB constraint (which enables CHP and PV sales)
(4e6)[23]	equal to run set (4e5) except that fuel cells have no runtime restrictions

Run 4a is the base case run, where no CHP / CCHP nor any other DER is allowed and all energy needs to be purchased from the local utility.

Run 4c3 represents full cost minimization with the ZNEB constraint. Very interesting is the finding that a lot of internal combustion engines (ICEs) are adopted in this case. Most of the adopted technologies are inefficient ICEs without any waste heat utilization (see Table 15-3). To compensate for this natural gas consumption PV needs to be installed. Please note that ZNEB can increase *building* CO_2 emissions if cost minimization is the main goal (see the increase in marginal CO_2 emissions in Table 14-13). However, this is also an accounting issue since the CO_2 emissions are always allocated at the place where the energy is consumed. This means sold PV electricity does not reduce the building CO_2 emissions.

Run 4e3, the pure CO_2 minimization case with fuel cell lifetime of 20 years instead of 10 years, reduces the annual energy costs by 3.7% and the CO_2 emissions by 4.4% compared to the base case (for further details see Table 14-13). The results are very interesting since the increased lifetime has no significant influence on the fuel cell adoption compared to run 4e from the *Basic Results of DER-CAM Optimization Memorandum* and the adopted CHP capacity hovers around 680 MW in 2030.

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[21] Run 4b and 4d are not shown in the tables as they represent the 2020 cost minimization respectively the 2020 carbon minimization cases, which are not shown in this memorandum.

[22] all carbon minimization runs with ZNEB constraint use a cost cap of 400%

[23] all carbon minimization runs with ZNEB constraint use a cost cap of 400%

Since the team was curious about the influence of the fuel cell constraint on the adoption pattern, run 4e4 was performed and surprisingly no major change in the fuel cell adoption could be observed.

Within run 4e5, which is based on 4e3, it is assumed that all buildings should operate as a zero-net energy building under building CO_2 minimization strategy. This run reduces the *onsite* carbon dioxide emissions by about 91% compared to the base case run 4a. On the other hand, the costs are about 60% higher as in the base case. A huge amount of PV, solar thermal, and electric storage needs to be installed to reach ZNEB status. Almost all installed natural gas fired units are with heat exchanger and waste heat utilization (see Table 15-3) and a total of 180 MW of CHP will be adopted, but the CHP capacity factor drops dramatically and reaches only roughly 20%. Please note that DER-CAM calculates the CO_2 emissions based on the energy used at the site/building. In other words, electricity purchased from the utility accounts for CO_2 emissions at the site. This implies that PV generated electricity sales do not reduce the carbon emissions at the site or building and this also drives onsite electric storage at CO_2 minimization strategies.

Run set 4e6 just looks into the influence of the fuel cell operational constraint and finds no significant impact.

Table 15-2: 2030 result summary of run set 4 for the considered commercial buildings (source: DER-CAM runs)[24],[25]

run	4a	4c3	4e3	4e4	4e5	4e6
run description:	base case	2030 (min US$) + ZNEB	2030 (minCO_2) + FC20yrs	2030 (minCO_2) + FC20yrs + w/o FC constraint	2030 (minCO_2) + FC20yrs + ZNEB	2030 (minCO_2) + FC20yrs + ZNEB + w/o FC constraint
annual energy costs (bln $)	5.3	0.4	5.1	5.1	8.5	8.4
annual energy costs (%)	100.0	7.3	96.3	96.7	159.7	158.6
change in annual energy costs (%)		(92.7)	(3.7)	(3.3)	59.7	58.6
annual marginal CO_2 emissions (Mt/a)	14.5	24.2	13.8	13.8	1.3	1.3
annual marginal CO_2 emissions (%)	100.0	167.4	95.6	95.7	9.2	9.2
change in annual marginal CO_2 emssions (%)		67.4	(4.4)	(4.3)	(90.8)	(90.8)
installed DG capacities (MW)		5,434.8	683.2	662.9	185.0	177.3
installed DG capacities (GW)		5.4	0.7	0.7	0.2	0.2
installed PV capacities (MW)		25,280.0	147.0	106.8	23,326.1	23,307.8
installed PV capacities (GW)		25.3	0.1	0.1	23.3	23.3
installed Solar Thermal capacities (MW)		112.8	472.8	501.6	19,177.3	19,016.4
installed Solar Thermal capacities (GW)		0.1	0.5	0.5	19.2	19.0
electricity produced by DG (without PV) (GWh)		23,260.7	4,018.2	3,855.6	322.0	322.0
PV and DG sales (GWh)		48,253.8	-	-	3,136.2	3,128.7
PV sales (GWh)		48,162.0				
cooling offset (GWh)		4,271.3	-	-	508.3	468.3
electric stationary storage (GWh)		1.6	0.1	0.1	82.9	82.3
heat storage (GWh)		0.2	-	0.0	43.8	42.4
DG capacity factor (%)		48.9	67.1	66.4	19.9	20.7

[24] CO_2 emission reduction runs without ZNEB assume that no building can have annual costs higher than in the base case.

[25] Please note in run 4e5 and 4e6 PV sales are not reported separately since the Excel sheet formats have been changed most recently and not all runs were using the new Excel sheet format. This has no influence on the results. It just means that some results were not collected for sum runs.

Within the ZNEB cost minimization (run 4c3) about 98% of the installed systems are internal combustion engines (ICE) and the rest are micro turbines (MT) (see Table 15-3). Within the CO_2 minimization runs 4e3 und 4e4 about 6% are fuel cells (FC) and the rest are MTs as these are the systems with the highest expected efficiency rate compared to the investment costs. In the CO_2 minimization runs almost only technologies are used that use waste heat for heating and domestic hot water and this improves the CO_2 balance. The ZNEB CO_2 minimization run 4e5 and 4e6 force distributed renewable energy systems and only MT systems are used in these cases as all available MT units are smaller as the smallest available FC technology. The smallest available FC unit within DER-CAM is 100 kW and the smallest MT unit is 60 kW.

Table 15-3: Installed capacities for run set 4 for the considered commercial buildings (source: DER-CAM runs)

run	4a	4c3	4e3	4e4	4e5	4e6
installed DG capacity (MW)	base case	2030 (min US$) + ZNEB	2030 (minCO2) + FC20yrs	2030 (minCO2) + FC20yrs + w/o FC constraint	2030 (minCO2) + FC20yrs + ZNEB	2030 (minCO2) + FC20yrs + ZNEB + w/o FC constraint
total installed DG capacity (MW)	-	5,434.8	683.2	662.9	185.0	177.3
ICE	-	4,795.0	-	-	-	-
ICE-HX	-	524.0	-	-	-	-
GT	-	25.0	-	-	-	-
GT-HX	-	-	-	-	-	-
MT	-	-	-	-	7.7	-
MT-HX	-	90.8	644.4	624.2	177.3	177.3
FC	-	-	-	-	-	-
FC-HX	-	-	38.8	38.8	-	-
% ICE of DG	-	97.9	-	-	-	-
% GT of DG	-	0.5	-	-	-	-
% MT of DG	-	1.7	94.3	94.2	100.0	100.0
% FC of DG	-	-	5.7	5.8	-	-

Table 15-4: Installed units for run set 4 for the considered commercial buildings (source: DER-CAM runs)

run	4a	4c3	4e3	4e4	4e5	4e6
installed units (pieces)	base case	2030 (min US$) + ZNEB	2030 (minCO2) + FC20yrs	2030 (minCO2) + FC20yrs + w/o FC constraint	2030 (minCO2) + FC20yrs + ZNEB	2030 (minCO2) + FC20yrs + ZNEB + w/o FC constraint
total number of installed DG units (pieces)	-	29,810	9,841	9,503	3,006	2,955
ICE	-	27,084	-	-	-	-
ICE-HX	-	2,096	-	-	-	-
GT	-	25	-	-	-	-
GT-HX	-	-	-	-	-	-
MT	-	-	-	-	51	-
MT-HX	-	605	9,686	9,348	2,955	2,955
FC	-	-	-	-	-	-
FC-HX	-	-	155	155	-	-
% ICE of DG	-	97.9	-	-	-	-
% GT of DG	-	0.1	-	-	-	-
% MT of DG	-	2.0	98.4	98.4	100.0	100.0
% FC of DG	-	-	1.6	1.6	-	-

Figure 15-1 shows results for some of the newly performed runs.

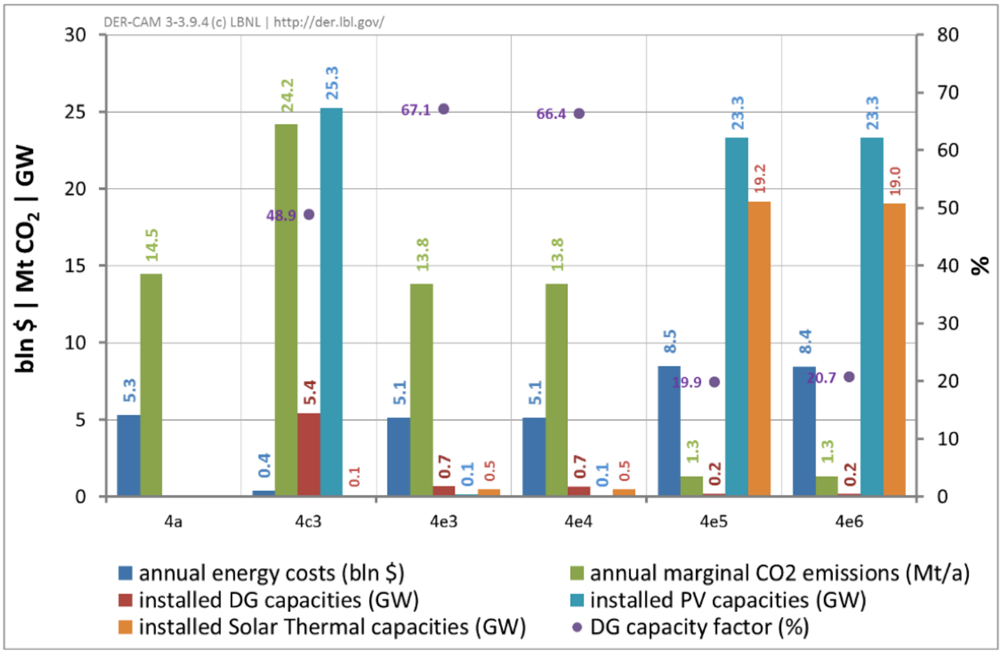

Figure 15-1. Result summary for runs in run set (4) for considered commercial buildings (source: DER-CAM runs)

Finally, please note that best average DG/CHP capacity factor, which is calculated by DER-CAM, does not exceed 67% and this is also in contrast to the frequently discussed 80%.

Figure 15-2 shows major results for some of the new runs of run set (4) compared to the base case 4a.

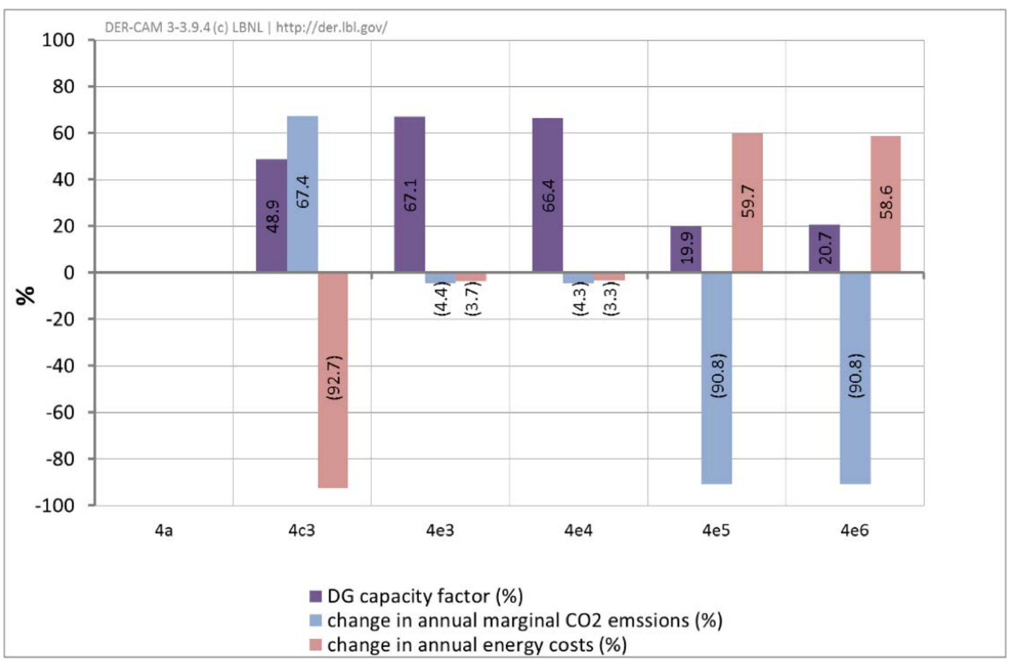

Figure 15-2. Result comparison for runs in run set (4) for considered commercial buildings (source: DER-CAM runs)

The “Basic Results of DER-CAM Simulation Memorandum” from May 2012 identified a CHP potential between 0.7 GW and 3 GW depending on the grid de-carbonization levels.

The new runs for improved lifetimes for fuel cells and with/without ZNEB constraint show a CHP potential between 0.2 GW and 0.6 GW.

All these results are based on the existing building stock and now building stock growth is considered. Also, please consider that the results are only for buildings between 100 kW and 5 MW electric peak loads and as explained in the “Collected Data Memorandum” and not all utility service areas are included in this study.

15.5 Building stock growth

As the CEUS database is based on 2006 building stock size all our optimization runs are based on the 2006 building stock as well. An average annual net growth of 1.0% can be assumed between 2010 and 2035 within the commercial floor space (EIA, 2012). Considering this annual growth between 2006 and 2030 and assuming that this is growth is evenly distributed over all building categories, the results from all DER-CAM runs can be multiplied directly by 1.27 ($= \left[(1+0.01)^{(2030-2006)}\right] = [1.01^{24}]$) to get the total 2030 results.

Considering the building stock growth the realistic CHP potential in 2030 can be between 0.9 GW and 3.81 GW based on the runs from the “Basic Results of DER-CAM Simulation Memorandum” from May 2012. The new runs for improved lifetimes for fuel cells and with/without ZNEB constraint show a CHP potential between 0.3 GW and 0.8 GW considering the building stock growth. Please refer to the “Collected Data Memorandum” for information on the considered buildings in this analysis.

15.6 Available space for PV and solar thermal

It is important to note that the area constraint for PV and solar thermal needed to be relaxed to allow ZNEB. Within non ZNEB DER-CAM runs we assume that the available space for PV and solar thermal is limited by the maximum area of a building. For the ZNEB runs this constraint was removed. On average about 370% of the building area would be necessary to be able to reach ZNEB (see Figure 15-3).

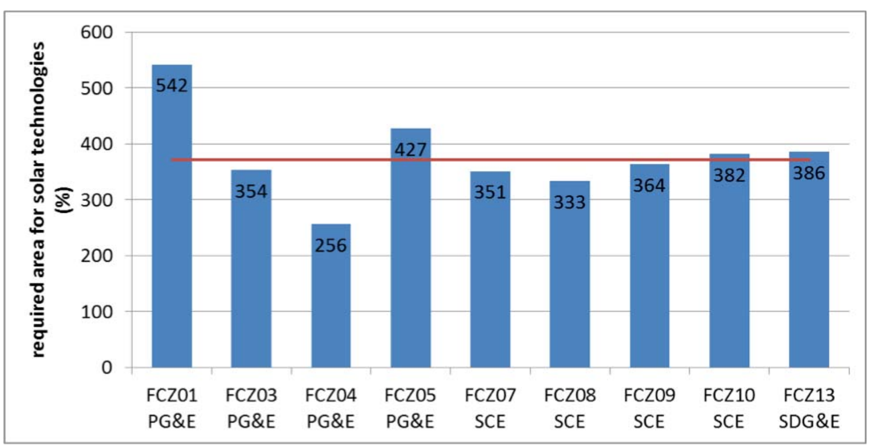

Figure 15-3. Required area for solar technologies for run set (4e5) for all considered buildings

15.7 Restaurant sector specific results

Additional restaurant profiles have been added to the already considered 138 building profiles (see "Basic Results of DER-CAM Simulation Memorandum" from May 2012). The CEUS database also provides restaurant profiles in all considered climate zones in California. With the usual used lower boundary for building peak demand of 100 kW_e only one restaurant in climate zone 4 would be considered in our runs (please refer to the "Collected Data Memorandum from Jan. 2012). Thus, for this memo we define a new lower peak demand boundary for restaurants. After defining 50 kW_e as new criteria large restaurants will be considered in each climate zone (Table 14-11). No small (annual demand < 90,000 kWh/a) or medium sized (annual demand ≥ 90,000, < 315,000 kWh/a) restaurants are still under consideration (building type size strata cutpoints according CEUS, 2006).

Table 15-5: Used restaurants profiles above 50 kW_e peak load (CEUS, 2006)

utility		PG&E				SCE				SDGE	total
category	size	FCZ 01	FCZ 03	FCZ 04	FCZ 05	FCZ 07	FCZ 08	FCZ 09	FCZ 10	FCZ 13	
REST	S	-	-	-	-	-	-	-	-	-	-
	M	-	-	-	-	-	-	-	-	-	-
	L	1	1	1	1	1	1	1	1	1	9

Abbreviation: REST: restaurants

PG&E service territory: climate zone FCZ01-FCZ05; SCE service territory: climate zone FCZ07-FCZ10; SDG&E service territory: climate zone FCZ13

Table 15-6: 2030 result summary of run set 4 for the considered restaurants (source: DER-CAM runs) [26]

run	4a	4c3	4e3	4e4	4e5	4e6
REST - run description:	base case	2030 (min US$) + ZNEB	2030 (minCO2) + FC20yrs	2030 (minCO2) + FC20yrs + w/o FC constraint	2030 (minCO2) + FC20yrs + ZNEB	2030 (minCO2) + FC20yrs + ZNEB + w/o FC constraint
annual energy costs (mln $)	342.4	63.6	342.1	342.1	468.8	458.5
annual energy costs (%)	100.0	18.6	99.9	99.9	136.9	133.9
change in annual energy costs (%)		(81.4)	(0.1)	(0.1)	36.9	33.9
annual marginal CO_2 emissions (kt/a)	1,076.2	1,303.2	1,073.4	1,073.4	379.8	379.8
annual marginal CO_2 emissions (%)	100.0	121.1	99.7	99.7	35.3	35.3
change in annual marginal CO_2 emssions (%)		21.1	(0.3)	(0.3)	(64.7)	(64.7)
installed DG capacities (MW)		201.6	-	-	-	-
installed DG capacities (GW)		0.2	-	-	-	-
installed PV capacities (MW)		1,524.4	-	-	1,571.2	1,636.4
installed PV capacities (GW)		1.5	-	-	1.6	1.6
installed Solar Thermal capacities (MW)		41.9	9.1	9.1	1,228.4	1,157.9
installed Solar Thermal capacities (GW)		0.0	0.0	0.0	1.2	1.2
electricity produced by DG (without PV) (GWh)		929.6	-	-	-	-
PV and DG sales (GWh)		2,591.7	-	-	713.0	711.9
PV sales (GWh)		2,589.9				
cooling offset (GWh)		115.7	-	-	57.0	31.2
electric stationary storage (GWh)		0.4	0.0	0.0	4.5	4.3
heat storage (GWh)		0.1	-	-	2.9	2.1
DG capacity factor (%)		52.6	-	-	-	-

The results basically show that CHP is not attractive in large restaurants with an electric peak load above 50 kW. Solar thermal and PV, as well as electric storage play a big role in ZNEBs.

[26] Please note in run 4e5 and 4e6 PV sales are not reported separately since the EXCEL sheet formats have been changed most recently and not all runs were using the new EXCEL sheet format. This has no influence on the results. It just means that some results were not collected for sum runs.

Figure 15-4 shows the results for the runs within run set (4) for restaurants.

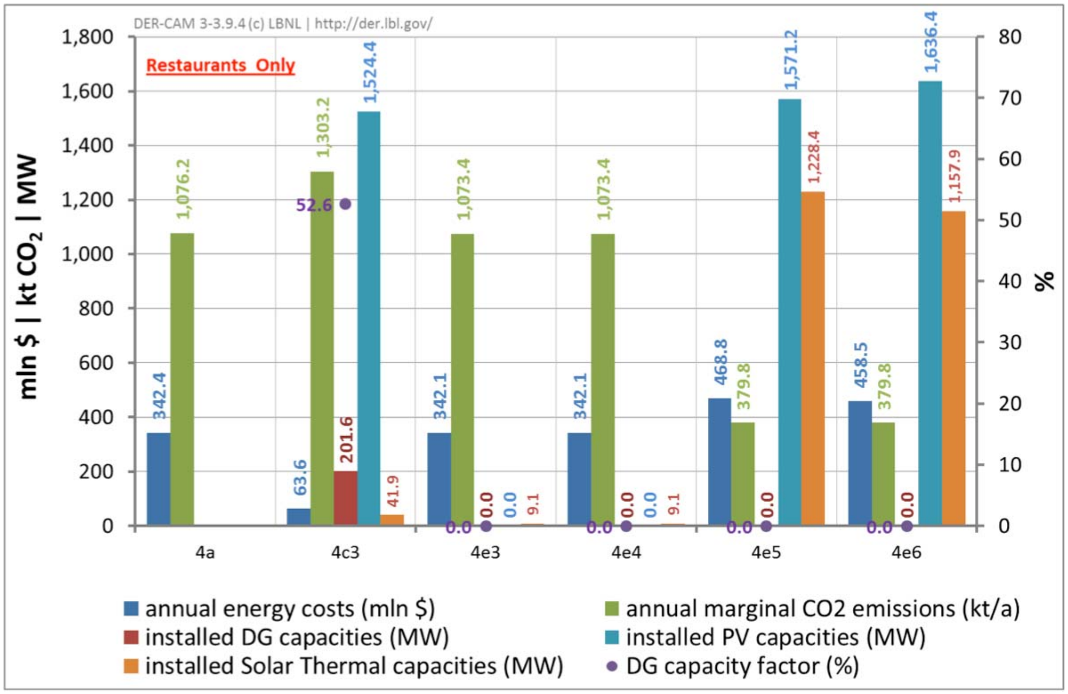

Figure 15-4. Result summary for runs in run set (4) for considered restaurants (source: DER-CAM runs)

Figure 15-5 and Figure 15-6 show the electricity supply and heat supply for a January and July week profile of the ZNEB optimization run 4e6 for a large restaurant within climate zone FCZ05 (supplier PG&E).

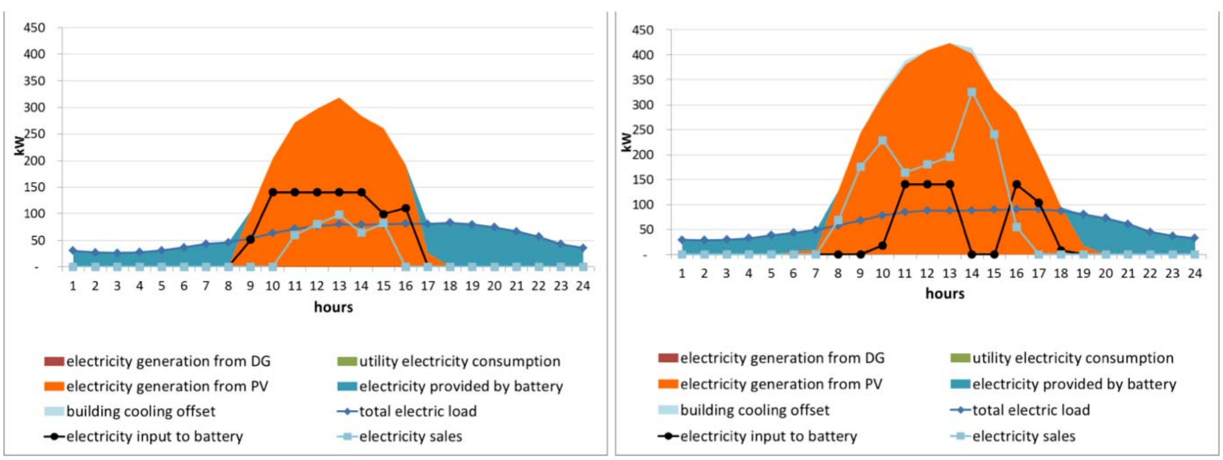

Figure 15-5. Diurnal electric patterns for weekdays for FCZ05 LREST, January and July, run 4e6

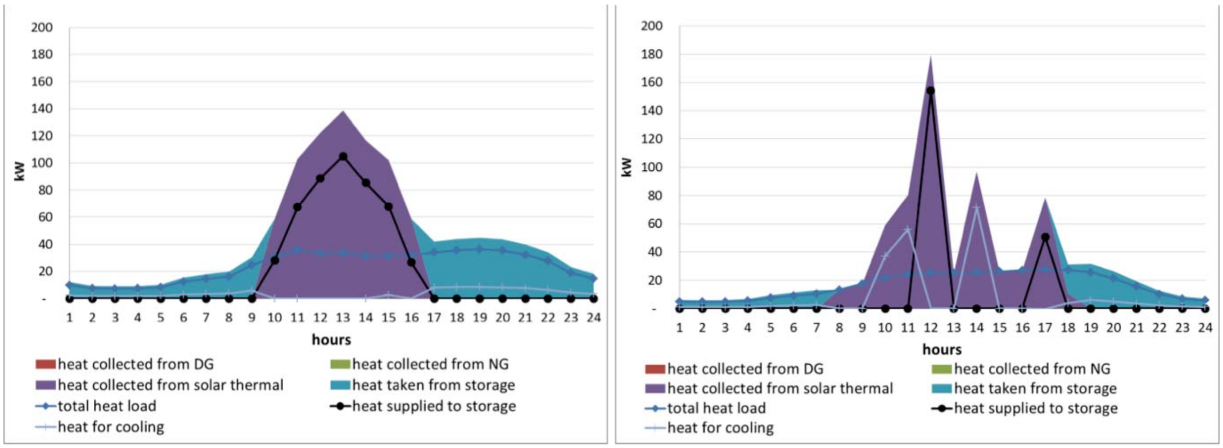

Figure 15-6. Diurnal heat patterns for weekdays for FCZ05 LREST, January and July, run 4e6

Figure 15-7 and Figure 15-8 show the electricity supply and heat supply for a January and July week profile of the ZNEB optimization run 4e6 for a large restaurant within the climate zone FCZ13 (supplier SDG&E).

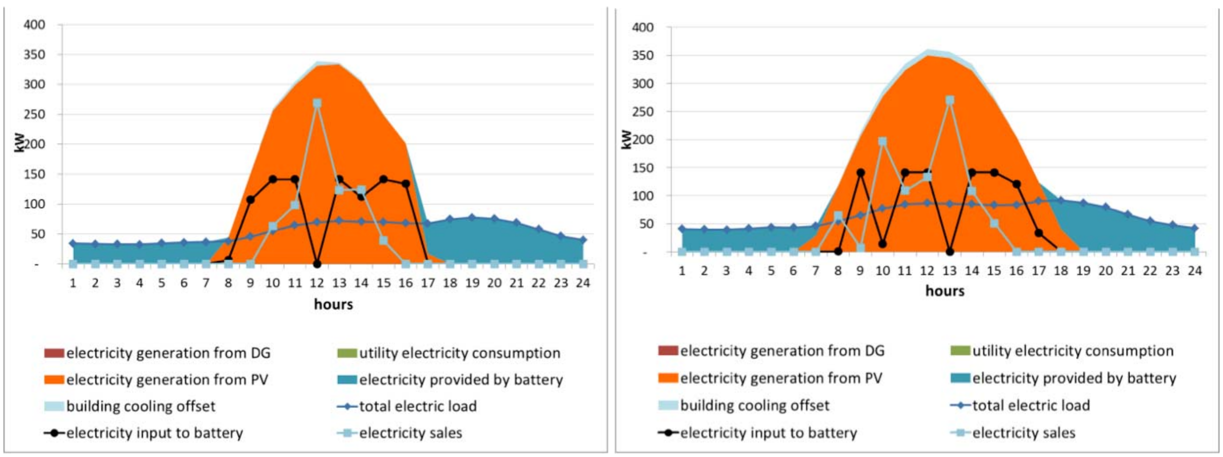

Figure 15-7. Diurnal electric patterns for weekdays for FCZ13 LREST, January and July, run 4e6

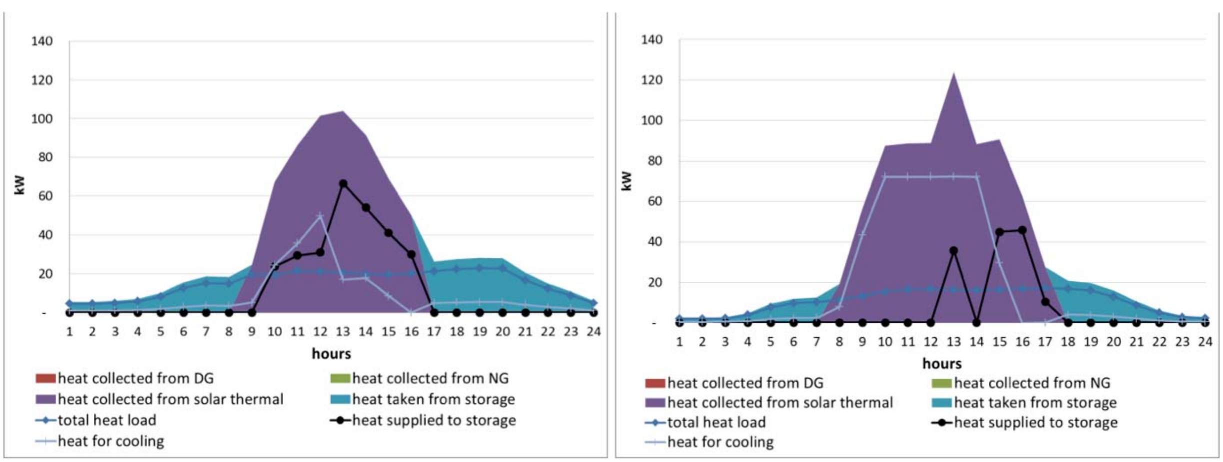

Figure 15-8. Diurnal heat patterns for weekdays for FCZ13 LREST, January and July, run 4e6

15.8 Significant challenges and problems observed

None within this memorandum, but one of the challenges identified in the *"Collected Data Memorandum"* from January 2012 still exists*:*

- CEUS details for restaurants
  The biggest problem is still the limited CEUS database information, especially for the restaurant sector. For this project Berkeley Lab would need the hourly load profiles for all major restaurants considered/simulated with eQuest within CEUS.

  We kindly request these information to be released by CEC and ITRON to improve the quality of this project. For more information please look at "Collected Data Memorandum" from January 2012.

15.9 Revision of Basic Results of DER-CAM Optimization Memo from May 2012

An Excel problem within the previous memo from May 2012 has occurred. The problem only impacts the electric storage results, which were not properly collected and aggregated in Excel. The optimization runs were performed correctly. Figure 15-9 and Figure 15-10 show the changed results. Please note that only the row "electric stationary storage (GWh)" has changed compared to the memorandum from May 2012.

	Results for CEC project CHPinREST								
	LBL price forecast for technologies;			LBL price forecast for technologies; higher NG prices;			LBL price forecast for technologies; higher NG prices; low marginal CO2 emissions;		
Run	1a	1c	1e	2a	2c	2e	3a	3c	3e
Run Description:	BaseCase	min US$	min CO_2	BaseCase	min US$	min CO_2	BaseCase	min US$	min CO_2
annual energy costs (bln $)	5.4	3.5	3.9	5.6	4.3	4.6	5.6	4.3	5.3
annual energy costs (%)	100.0	63.8	72.7	100.0	77.2	83.0	100.0	77.0	94.7
change in annual energy costs (%)		- 36.2	- 27.3		- 22.8	- 17.0		- 23.0	- 5.3
annual marginal CO2 emissions (Mt/a)	21.8	19.5	16.4	21.8	19.9	18.1	14.5	16.7	13.7
annual marginal CO2 emissions (%)	100.0	89.4	75.2	100.0	91.4	83.2	100.0	115.7	94.6
change in annual marginal CO2 emssions (%)		- 10.6	- 24.8		- 8.6	- 16.8		15.7	- 5.4
installed DG capacities (MW)		5,379.3	4,314.9		3,893.7	3,056.4		3,879.4	799.7
installed DG capacities (GW)		5.4	4.3		3.9	3.1		3.9	0.8
installed PV capacities (MW)		901.2	1,260.5		617.0	795.8		658.7	313.5
installed PV capacities (GW)		0.9	1.3		0.6	0.8		0.7	0.3
installed Solar Thermal capacities (MW)		-	328.9		18.4	195.7		20.6	427.6
installed Solar Thermal capacities (GW)		-	0.3		0.0	0.2		0.0	0.4
electricity produced by DG (without PV) (GWh)		26,609.8	24,097.7		17,723.3	17,326.1		17,769.9	4,594.2
cooling offset (GWh)		2,558.2	2,338.6		1,670.9	1,564.6		1,652.0	19.9
electric stationary storage (GWh)		0.2	0.5		0.1	0.9		0.2	0.1
DG capacity factor (%)		56.5	63.8		52.0	64.7		52.3	65.6

Figure 15-9. Corrected results for run sets (1) - (3)

Results for CEC project CHPinREST
LBL price forecast for technologies;
higher NG prices;
low marginal CO2 emissions;
higher electricity prices for big customers;
Nox treatment costs for ICE's

run	4a	4c	4c2	4e	4e2
run description:	base case	2030 (min US$)	2030 (min US$) + sales	2030 (min CO_2)	2030 (min CO_2) + sales
annual energy costs (bln $)	5.3	4.5	4.3	5.1	5.1
annual energy costs (%)	100.0	85.0	81.3	96.4	96.2
change in annual energy costs (%)		(15.0)	(18.7)	(3.6)	(3.8)
annual marginal CO_2 emissions (Mt/a)	14.5	15.7	16.4	13.8	13.8
annual marginal CO_2 emissions (%)	100.0	108.4	113.2	95.6	95.4
change in annual marginal CO_2 emssions (%)		8.4	13.2	(4.4)	(4.6)
installed DG capacities (MW)		2,528.5	3,043.8	695.4	787.7
installed DG capacities (GW)		2.5	3.0	0.7	0.8
installed PV capacities (MW)		496.8	979.4	147.0	134.9
installed PV capacities (GW)		0.5	1.0	0.1	0.1
installed Solar Thermal capacities (MW)		18.8	7.0	472.7	494.2
installed Solar Thermal capacities (GW)		0.0	0.0	0.5	0.5
electricity produced by DG (without PV) (GWh)		13,402.4	15,802.1	4,073.9	4,524.0
PV and DG sales (GWh)		-	1,713.1	-	1.3
PV sales (GWh)					
cooling offset (GWh)		1,031.0	1,112.3	-	13.9
electric stationary storage (GWh)		0.4	0.5	0.1	0.3
DG capacity factor (%)		60.5	59.3	66.9	65.6

Figure 15-10. Corrected results for run set (4)[27]

15.10 References

AEO, 2009, Assumptions to the Annual Energy Outlook 2009. Report #:DOE/EIA-0554(2009). Available at: http://www.eia.gov/oiaf/archive/aeo09/assumption/index.html

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Stadler M., Marnay C., Cardoso G., Lipman T., Mégel O., Ganguly S., Siddiqui A., Lai J. ,2010, "The CO2 abatement potential of California's mid-sized commercial buildings," Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-3024E. Available at: http://eetd.lbl.gov/EA/EMP/emp-pubs.html.

[27] Please note that in these runs PV sales are not reported separately since the EXCEL sheet formats have been changed most recently and not all runs were using the new EXCEL sheet format. This has no influence on the results. It just means that some results were not collected for sum runs.

15.11 Acronyms and abbreviations

$/kWh$_t$	US Dollars per kWh thermal
bln $	billion US Dollars
CEUS	California Commercial End-Use Survey
DER-CAM	Distributed Energy Resources Customer Adoption Model
DG	distributed generation
GHG	greenhouse gas
GW	Giga Watt = 10^9 Watt
kW	kW = 10^3 Watt
kW$_e$	kW electricity
mln $	million US Dollars
Mt/a	metric tons per year
MW	Mega Watt = 10^6 Watt
PG&E	Pacific Gas and Electric
PEMFC	Proton Exchange Membrane Fuel Cell
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SOFC	Solid Oxid Fuel Cell
ZNEB	zero net energy building