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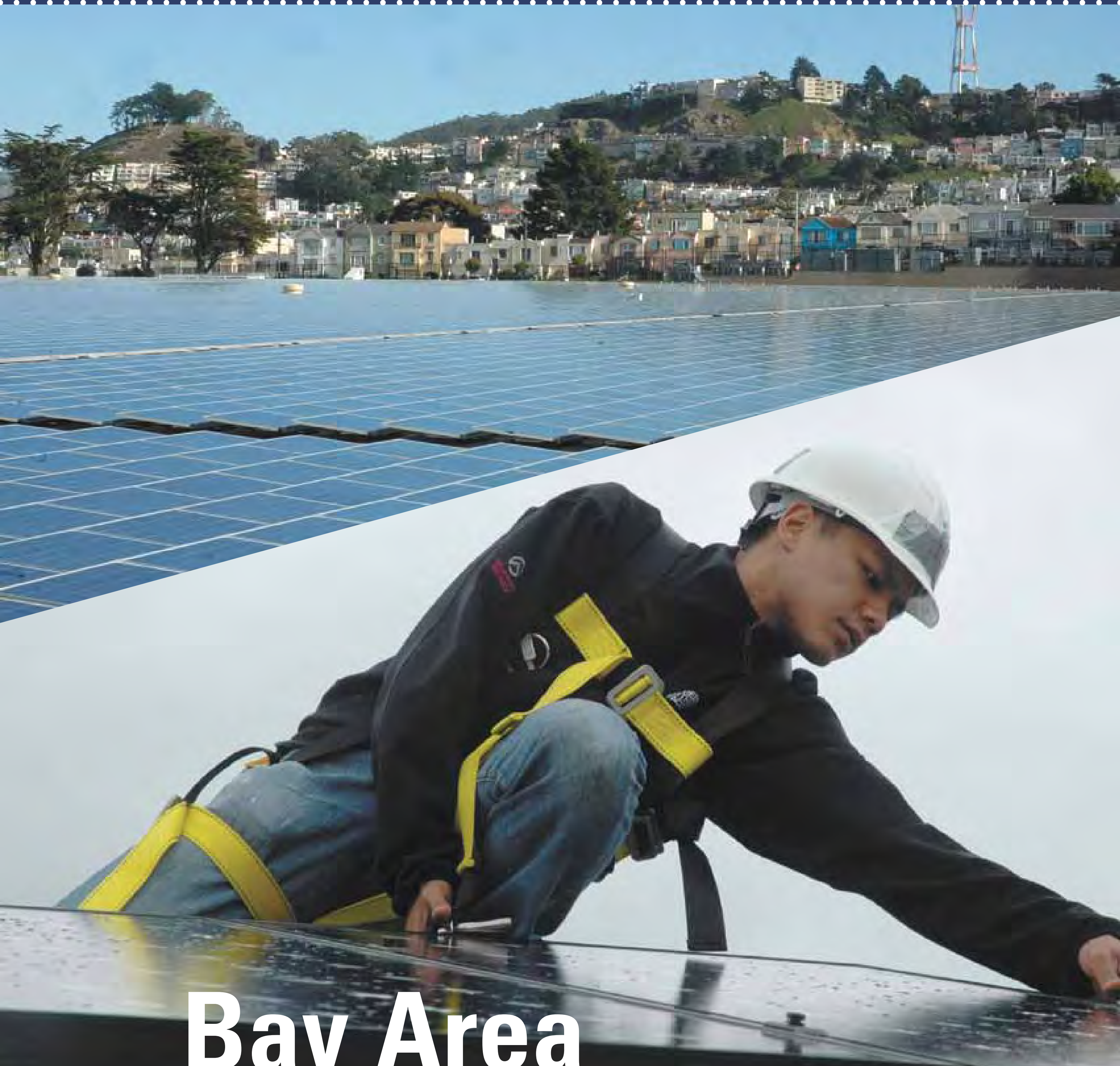

Bay Area Smart Energy 2020

By Bill Powers, P.E.
Powers Engineering

March, 2012

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Bay Area Smart Energy 2020

By Bill Powers, P.E.
Powers Engineering,
San Diego, California
March, 2012
Executive editor:
Rory Cox
Dedicated to the memory of Charles McGlashan

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Forward

THE WINDOW OF OPPORTUNITY TO BUILD the energy future of California is wide open. In 2011, Governor Jerry Brown called for a 33 percent renewable portfolio standard by 2020, AND for over half of that generation to come from locally generated, "distributed" power sources. As this is an unprecedented goal in the US, the Governor is seeking advice. And that is why *Bay Area Smart Energy 2020* is needed now.

Bay Area Smart Energy 2020 is a roadmap to rapid, cost-effective conversion to clean energy that relies on local resources. Our region is the right place to build the grid of the future. The San Francisco Bay Area is one of the world's leading centers of clean energy innovation and environmental awareness. The region has a long tradition of environmental leadership dating back to John Muir, and the Bay Area is host to technology leaders, progressive venture capitalists, effective government, environmentally-oriented labor leadership, and hundreds of leading environmental and social justice organizations.

Silicon Valley is a lightning rod for clean energy innovation, hosting countless companies that are developing cutting edge technologies in solar, wind, and energy efficiency, along with the software and integration technology to make it all work. Many of these successful and promising companies were jumpstarted with billions of dollars from local venture capitalists.

Regional academic institutions like UC Berkeley, Lawrence Berkeley National Lab and Stanford are leading the way in clean energy research, while our elected leaders regularly support laws and programs to incentivize a cleaner, greener environment. The concept of "green collar jobs" has caught fire in the Bay Area, thanks to the vision of groups like the Oakland-based Ella Baker Center and local leaders like Van Jones. Progressive labor leaders have strongly supported California's landmark climate change laws, understanding that clean energy is the growth industry of the 21st century.

Despite these promising Bay Area conditions, however, less than 20 percent of our region's electric power today comes from truly clean sources. Amazingly, clean energy is too often under attack, with many politicians across the US working to undermine clean energy incentive programs, while offering no solutions to solve climate change or put people back to work.

If we build it, we will win. As this report demonstrates so well, the tools and technology already exist and are becoming more efficient, sophisticated and cost-effective. By developing local, clean energy projects and production, we will put people to work, reinvigorate our regional economy, and build a truly healthy and sustainable energy future.

Let's get going!

Francesca Vietor

Environment Program Officer, San Francisco Foundation and Commissioner, San Francisco Public Utilities Commission

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Acronyms

ACEEE	American Council for an Energy-Efficient Economy
AMP	Alameda Municipal Power
ARRA	American Recovery and Reinvestment Act
BASE	Bay Area Smart Energy
BART	Bay Area Rapid Transit
BLM	Bureau of Land Management
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCA	Community Choice Aggregation
CEC	California Energy Commission
CES	Community Energy Storage
CHP	Combined heat and power
CO2	Carbon dioxide
CPAU	City of Palo Alto Utilities
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
CVEUP	Chula Vista Energy Upgrade Project
DG	distributed generation
DOE	Department of Energy
DRA	Division of Ratepayers Advocates
DR	demand response
DWR	Department of Water Resources
EPRI	Electric Power Research Institute
FERC	Federal Energy Regulatory Commission
FHFA	Federal Housing Finance Agency
FIT	feed-in tariff
GHG	greenhouse gases
GW	gigawatt, equals 1,000 megawatts.
GWh	gigawatt-hour
HVAC	heating, ventilation, and air conditioning
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
IEPR	Integrated Energy Policy Report
IOU	investor-owned utility
LABC	Los Angeles Business Council
LADWP	Los Angeles Department of Water & Power

LCOE	levelized cost-of-energy
LCR	local capacity requirement
MEA	Marin Energy Authority
MPR	market price referent
MW	megawatt, equals 1,000 kilowatts
MWh	megawatt-hour
NCPA	Northern California Power Agency
NREL	National Renewable Energy Laboratory
OPA	Ontario Power Authority
OPUC	Oregon Public Utilities Commission
PACE	property assessed clean energy
PHEV	plug-in electric vehicle
PG&E	Pacific Gas & Electric
POU	publicly-owned utility
PPA	power purchase agreement
PURPA	Public Utility Regulatory Policy Act
PV	photovoltaic
QF	qualifying facility
RAM	renewable auction mechanism
RETI	Renewable Energy Transmission Initiative
RPS	Renewable Portfolio Standard
SDG&E	San Diego Gas & Electric
SCE	Southern California Edison
SCPPA	Southern California Public Power Authority
SEER	seasonal energy efficiency ratio
SEP	supplementary energy payments
SFPUC	San Francisco Public Utilities Commission
SGIP	self generation incentive program
SJVPA	San Joaquin Valley Power Authority
SMUD	Sacramento Municipal Utility District
SVP	Silicon Valley Power
SWRCB	State Water Resources Control Board
T&D	transmission & distribution
TOD	time-of-delivery
TOU	time-of-use
TREC	tradable renewable energy credit
TURN	The Utility Ratepayer Network
UCLA	University of California Los Angeles
ZNE	zero net energy

1. Executive Summary

BAY AREA SMART ENERGY 2020 (BASE 2020) is a distributed generation strategy for minimizing greenhouse gas (GHG) emissions from electricity usage in the nine counties surrounding San Francisco Bay. BASE 2020 prioritizes energy efficiency, rooftop and distributed solar photovoltaics (PV) of all types, and local combined heat and power plants to meet the Bay Area's electricity needs. BASE 2020 is to a large degree the application of California's strategic energy vision, embodied in the *California Energy Action Plan* and the *California Energy Efficiency Strategic Plan*, to the Bay Area.

A framework objective of BASE 2020 is to convert existing homes and businesses to zero net energy buildings. This is a core strategy of the *Energy Efficiency Strategic Plan*, which was co-authored by Pacific Gas & Electric (PG&E), the Bay Area's investor-owned (private) utility. The concept of "zero net energy" is to develop or retrofit buildings so they produce at least as much electricity on site as they use. A combination of energy efficiency measures and rooftop PV are used to achieve zero net energy. Following a similar timeline to that established in the *Energy Efficiency Strategic Plan,* BASE 2020 envisions the conversion of 25 percent of existing Bay Area homes and commercial buildings to zero net energy buildings by 2020. All new homes and businesses will be built as zero net energy structures from 2015 onward.

BASE 2020 will achieve a Bay Area GHG reduction from electricity usage of more than 60 percent, compared to a 2008 baseline year, relying on proven off-the-shelf technologies and policies. At the same time, BASE 2020 will lower utility costs for Bay Area businesses and residents over a "business as usual" case, in large part due to: 1) emphasis on cost-effective energy efficiency measures and 2) the ongoing, spectacular drop in PV system prices.

The peak demand met by Bay Area utilities will decline by more than 50 percent, from approximately 14,000 megawatts (MW) today to 6,500 MW in 2020, as energy efficiency, state-of-the-art air conditioning and commercial building chiller systems, local PV, combined heat and power, and battery storage displace grid power. This will substantially reduce air pollution in Bay Area communities adjacent to large existing natural gas-fired peaker plants that will operate much less frequently on hot summer days.

BASE 2020 at a Glance

- **Solar PV:** Nearly 4,000 MW of local PV will be installed in the Bay Area by 2020 to achieve zero net energy targets. The inflow of this local PV on hot summer days will reduce natural gas-fired peaker plant air pollution, relieve grid congestion, and reduce wear-and-tear on grid equipment in the Bay Area.

- **Energy Efficiency:** Efficiency measures will reduce Bay Area electricity demand from approximately 58,000 gigawatt-hours per year to about 42,000 gigawatt-hours per year. This represents an average energy efficiency reduction, compared to a 2008 baseline, of 25 to 30 percent in Bay Area residential, commercial, and industrial buildings, and agricultural operations.

- **Air Conditioning:** Electricity consumption by air conditioning units, the primary cause of high summertime peak loads, will be reduced 50 percent by 2020 – consistent with the *Energy Efficiency Strategic Plan* – by methodical phase-in of high efficiency replacement units and on/off cycling of most units on hot days.

- **Combined Heat and Power:** 840 megawatts of new combined heat and power will also be added in the Bay Area, using a fuel mix consisting of at least 50 percent biomethane or biogas.

- **Geothermal:** Up to 300 megawatts of additional geothermal capacity will be added at the The Geysers in Sonoma County through cooling system upgrades to existing geothermal units.

- **Wind:** 300 megawatts of planned and under construction wind additions in Solano County are incorporated into BASE 2020.

- **Energy Storage:** 400 megawatts of battery storage will be integrated with the Solano County wind production area to convert Solano County wind power into a round-the-clock baseload resource. 200 megawatts of distributed battery storage, which can be expanded over time, will be integrated with residential and commercial PV systems to serve as peaking capacity and to provide the structure for community-scale microgrids.

- **Financing and Policy Tools:** The primary vehicles to achieve the reduction in GHG emissions will be 1) Property Assessed Clean Energy (PACE); 2) clean energy payments – also known as feed-in tariffs – to incentivize maximum local PV development; and 3) the expansion of Community Choice Aggregation. PACE is a financing mechanism pioneered in Berkeley and refined in Sonoma County that allows home and business owners to invest in energy efficiency and rooftop PV with no up-front expense. Repayment is realized as an assessment added to property taxes. Carefully calibrated clean energy payments in Germany have led to very high PV installation rates, approximately 7,000 megawatts per year, with average PV system installed costs that are much lower than those in California. Community Choice Aggregation allows local communities to form a public energy authority separate from PG&E to select the sources of electricity supply and the quantity of green power provided to customers. Community Choice Aggregation was successfully launched in Marin County in 2010, is in the process of being launched in San Francisco, and is under consideration in Sonoma County.

1.1 – The Policy Context

For BASE 2020 to drive the Bay Area to a robust clean energy economy based on zero net energy buildings, utility actions must be brought into alignment with the state's *Energy Efficiency Strategic Plan*. One example is PG&E's ability to purchase renewable energy credits from rooftop PV system operators to help the company meet its 2020 RPS target of 33 percent. This provides a mechanism to enhance the economics of rooftop PV while reducing overall RPS costs to ratepayers.

California's *Energy Action Plan* prioritizes energy efficiency over all other methods for addressing electricity demand. State policy views rooftop PV as integral to achieving the energy efficiency ideal – zero net energy buildings. California's *Energy Efficiency Strategic Plan* and BASE 2020 rely on local distributed PV to achieve zero net energy buildings.

Yet state policy has not yet directly addressed the fundamental conflict between a state strategy that is built around zero net energy buildings, which will substantially reduce demand for utility-supplied electricity, and the traditional investor-owned utility revenue model that is dependent on ever-expanding demand for utility-supplied electricity. Investor-owned utilities increase revenue by building more transmission lines, distribution substations, power plants, and meters, and passing along the cost of this infrastructure to ratepayers at a guaranteed rate-of-return. This model must change.

One of the geothermal power plants at The Geysers.

1.2 BASE 2020 Sources of Energy

1.2.1 Solar PV

The Bay Area will displace nearly 8,000 gigawatt-hours per year of electricity purchases through the installation of nearly 4,000 megawatts of rooftop PV. The addition of this amount of PV represents the quantity necessary for 25 percent of existing Bay Area residential and commercial buildings to achieve zero net energy by 2020.[1]

Solar electricity generated on the distribution grid at or near the point-of-use has an "avoided cost" (meaning the cost that would be borne by the utility to produce and deliver the same electricity from new conventional sources) of over $0.22 per kilowatt-hour without including the renewable energy value of the solar electricity. As a result, an equitable payment for this solar electricity, in the range of $0.20 per kilowatt-hour, would place no additional financial burden on utility customers without rooftop PV systems. Any distributed PV program payment structure that fairly accounts for rooftop PV value will result in rapid growth in rooftop PV installations.

The state's "Million Solar Roofs" program, which includes the *California Solar Initiative,* will add 3,000 megawatts of primarily rooftop PV by the end of 2016. About 550 megawatts of this capacity will be added in the Bay Area. This is a "net metering" program, meaning the solar generators swap electricity with PG&E at retail electricity rates. The solar generator can be credited with up to 100 percent of the building's annual electricity demand. Net metering at retail electricity rates is a core financial element in the cost-effectiveness of zero net energy building retrofits.

Currently PV installed under net metering does not count directly toward the utility's 33 percent RPS target. However, the green attribute of net-metered solar electricity, the renewable energy credit, may now be purchased by PG&E to count toward the 33 percent RPS target as a result of California Public Utility Commission (CPUC) regulatory action in 2010. These renewable energy credit payments, currently capped at $50 per megawatt-hour through 2013, have the potential to shift the renewable energy playing field in favor of rooftop PV.

Net metering does not shift costs to customers without rooftop PV when all relevant costs and benefits of net-metered PV systems are evaluated together. Net metering does accelerate California's shift to green energy. However, the current cap on net-metered PV capacity, five percent of peak utility demand, will become an obstacle in the near-term to zero net energy building retrofits if this cap is not revised upward or removed entirely.

Rooftop PV is cost-effective. Commercial rooftop PV systems are being built in California with contract prices of $0.14 per kilowatt-hour. This compares to utility-scale PV and solar thermal contracts approved by the CPUC in 2011 ranging from $0.15 to 0.18 per kilowatt-hour. Residential systems have been installed in California for as little as $4.40 per watt, equivalent to about $0.20 per kilowatt-hour. Germany has the highest PV installation rate in the world at over 7,000 megawatts per year, and is installing residential rooftop PV at an average of $3 per watt and small commercial rooftop PV at $2.70 per watt. These PV capital costs are equivalent to $0.14 per kilowatt-hour and less than $0.10 per kilowatt-hour, respectively.[2] The German labor market is more expensive than the California market.

One reason for the lower installed cost of German PV systems is standardized permitting. The Department of Energy is funding the development of a scalable standard template for solar PV permitting, inspection and interconnection by states, utilities and local jurisdictions. The Bay Area will be a pilot site for establishing a regional standardized solar permitting process under the Department of Energy program.

Germany has achieved its high rooftop PV installation rate using a simple clean energy payment system (or feed-in tariff) that provides PV generators some income above the cost of production. The payments are revised on a six-month basis to assure that clean energy payment pricing reflects current PV market costs. It is reasonable to assume that at high volume under a similar clean energy payment program, the California rooftop PV market would reflect the same PV cost efficiencies being realized in the German market.

PV panels equipped with integrated microinverters that convert direct current electricity to alternating current at the panel are reducing cost and simplifying installation. The lowest published cost to date for residential PV systems in California, $4.40 per watt, is being offered by Open Neighborhoods in Los Angeles for a 2 kilowatt system using microinverters. In general, PV system prices are anticipated to continue falling at a rate of about 15 percent per year for at least the next few years.

California's utility-scale RPS program is producing some results, but at great cost to ratepayers. According to the CPUC's Division of Ratepayer Advocates, the renewable energy contracts signed by PG&E and California's other investor-owned utilities through the summer of 2010 will incur $6 billion in additional costs above the baseline market reference price if they are built. Many more high-priced contracts have been signed since 2010. For example, the dissenting commissioner on the November 2011 CPUC vote to approve a long-term contract for the 250 megawatt Mojave solar thermal project objected to ratepayers paying $1.25 billion over market price for this one project, stating that ratepayers should be getting double the renewable energy for the cost of the contract.

Contract terms between utilities and generators for renewable energy of all types and natural gas-fired turbines are confidential. This confidentiality is controversial. Legislation signed into law in 2011, SB 836, is beginning to shed light on the cost of specific RPS contracts. Greater contract transparency would draw attention early to high-priced contract proposals and should lower the cost of future long-term utility-scale contracts entered into by PG&E.

In addition, remote utility-scale projects generally require new transmission capacity to reach demand centers. Transmission is expensive. The cost of new transmission lines to reach remote solar and wind sites could exceed $15 billion statewide if the investor-owned utility RPS compliance strategy is followed. Upgrading the existing transmission system to accommodate these new power flows will add billions more in cost. As a result, a large ground-mounted PV array in the Mojave or Colorado Desert produces electricity at an all-in cost, including the cost of new transmission, as much as 50 percent greater than the cost-of-electricity produced by a 500 kilowatt PV array on a big box retail outlet or similar large commercial building in Oakland.

The Vaca Dixon solar project. Photo: Next 100.com

Conclusions/Recommendations:

- Nearly 4,000 megawatts of rooftop PV will need to be online in the Bay Area by 2020 to meet the BASE 2020 rooftop PV target.
- The avoided cost to PG&E of rooftop PV systems in the Bay Area is at least $0.22 per kilowatt-hour without considering the value of the renewable energy credits.
- Any price paid for rooftop PV below $0.22 per kilowatt-hour would benefit all ratepayers by providing electricity at a lower cost than PG&E would charge if it were supplying the same electricity from new conventional sources, after time-of-delivery cost, line losses, and transmission and distribution costs are accounted for.
- New commercial rooftop PV systems in California can deliver electricity at contract prices in the range of $0.14 per kilowatt-hour without state PV incentives.
- Lowest-cost residential PV systems can deliver electricity at $0.20 per kilowatt-hour without state PV incentives.
- Rapid price declines continue in both the commercial and residential rooftop PV markets.
- The renewable energy credits associated with net-metered rooftop PV can be sold as tradable renewable energy credits to assist PG&E reach its RPS target.
- Both net-metering and clean energy payment PV programs will make substantial contributions to meeting the BASE 2020 rooftop PV target.
- Equitable net metering must be preserved and existing net metering caps lifted for zero net energy programs like PACE to function to their potential.
- Equitable clean energy payments that closely track real-time PV price reductions are a proven mechanism for rapidly expanding rooftop PV installations at lowest cost.
- An equitable clean energy payments program in California would provide a mechanism for the state to replicate the rapid rooftop PV growth rate in Germany.

1.2.2 Combined Heat and Power

Combined heat and power refers to facilities that use a small gas turbine, engine, or fuel cell to generate both electricity and useful heat. Combined heat and power facilities are commonly found at college campuses, hospitals, and commercial and industrial complexes.

BASE 2020 incorporates the AB 32 *Global Warming Solutions Act Scoping Plan* target of 4,000 megawatts of new combined heat and power by 2020. A primary role of the new combined heat and power will be to displace coal power purchases by PG&E, purchases made either directly from in-state coal generators or as a component of wholesale power market purchases. This will result in approximately 840 megawatts of new combined heat and power in the Bay Area by 2020.

The avoided cost to PG&E of combined heat and power in the Bay Area is about $0.18 per kilowatt-hour. Combined heat and power projects can cost-effectively deliver electricity at contract prices as low as $0.12 per kilowatt-hour. The fuel composition target for combined heat and power in BASE 2020 is 50 percent biogas or biomethane, combined with natural gas, to reduce the GHG footprint of new combined heat and power to approximately 300 pounds of CO_2 per megawatt-hour. This is less than half the GHG footprint of a state-of-the-art base load combined cycle plant.

Conclusions/Recommendations:

- Any fixed payment paid to combined heat and power operators below $0.18 per kilowatt-hour would benefit all PG&E ratepayers.
- Establish a fixed payment for combined heat and power of at least $0.12 per kilowatt-hour to assure that combined heat and power projects are built.

1.2.3 Geothermal

The conversion of the existing geothermal plants at The Geysers to parallel wet-dry cooling systems, which should reduce evaporative water loss by 80 to 90 percent over current practice, could increase sustainable output from The Geysers by as much as 300 megawatts. Total installed capacity at the The Geysers reached nearly 2,000 megawatts during the geothermal plant building boom of the 1980s. Production from The Geysers dropped dramatically in the late 1980s due to too much geothermal reservoir steam/water being evaporated in the wet cooling towers used on all of the nearly 20 geothermal plants located there. The construction of a treated wastewater and freshwater pipeline to The Geysers in the late 1990s, to inject 8 million gallons per day into the geothermal reservoir, stabilized output at around 900 megawatts.

The incremental production from parallel wet-dry cooling retrofits could potentially produce the lowest cost renewable energy in the state and would improve the sustainability of the geothermal resource. However, given that all of the geothermal plants are using the same extended geothermal reservoir, a comprehensive conversion of all the existing geothermal plants would be necessary to realize the full benefit of the wet-dry cooling conversions.

Conclusions/Recommendations:

- The California Energy Commission should conduct a comprehensive evaluation of the cost and benefits of retrofitting existing geothermal plants at The Geysers with parallel wet-dry cooling systems to increase sustainable output at The Geysers by up to 300 megawatts.
- The conclusions of this study, if favorable, would serve as the basis for initiating necessary regulatory steps to retrofit the existing geothermal plants at The Geysers to parallel wet-dry cooling.

1.2.4 Wind

300 megawatts of new wind projects already planned or under construction in Solano County are incorporated into BASE 2020.

1.2.5 Energy Storage

400 megawatts of battery storage will be integrated to the Solano County wind production area to provide 400 megawatts of peaking power and to smooth output from the wind generators. 200 megawatts of battery storage will also be added to residential and commercial Bay Area buildings to absorb mid-day PV output, provide peaking capacity, address the intermittency of solar electricity production, and serve as the foundation of community-scale microgrids that can operate around-the-clock on electricity supplied by rooftop PV. Pilot community energy storage projects are underway at various utilities. The cost of this battery capacity, in 2012 prices, is less than the expected capacity payments for new peaking gas turbines.

Conclusions/Recommendations:

- Energy storage is a good match for the high summertime output of Solano County wind farms. The California Energy Commission should conduct a study of the economic and grid reliability benefits of integrating 400 megawatts of battery storage with the Solano County wind farms.
- If the study results are favorable, the state should move forward with the regulatory steps necessary to bring the 400 megawatt battery storage facility online prior to 2020.
- 200 megawatts of distributed battery storage should be added at the neighborhood level. Community energy storage systems are a green substitute for conventional peaking gas turbine resources and an essential building block in eventual community-level microgrids.

1.2.6 Solar Hot Water

Solar hot water heating is a cost-effective and relatively untapped option for reducing natural gas demand. An analysis conducted of solar water heating natural gas savings potential in California determined a potential reduction of approximately 120 billion cubic feet of natural gas per year, about 20 days of natural gas supply. This is about 5 percent of the yearly statewide consumption of natural gas.

The *Solar Hot Water and Efficiency Act of 2007* authorized a ten-year incentive program for solar water heaters with a goal of promoting the installation of 200,000 systems in California by 2017. This is an average installation rate statewide of 20,000 systems per year. Germany has installed as many as 200,000 solar hot water systems in one year. PG&E has over 5 million residential and commercial customers. An installation rate of 200,000 systems per year is a realistic and achievable goal in PG&E territory.

Conclusions/Recommendations:

- The state's current solar hot water program must grow to hundreds of thousands of installations per year over the next decade if solar hot water systems are to put significant downward pressure on residential and commercial natural gas consumption.
- The 2020 solar hot water target for PG&E should be about 1.5 million systems, equal to about 25 percent of PG&E's customers. This is consistent with the target of retrofitting 25 percent of PG&E homes and businesses with rooftop PV by 2020. Over half of these retrofits would occur in the Bay Area. A second target is to reach and sustain a solar hot water retrofit rate of 200,000 per year by 2020 in PG&E territory.

170,735-sq.-ft. net zero emissions office building prototype in St. Louis, Mo. Illustration: Hellmuth, Obata and Kassabaum.

1.3 Energy Efficiency and Peak Demand Reduction

1.3.1 Energy Efficiency

The *Energy Efficiency Strategic Plan* calls for 25 percent of residences to reach 70 percent reduction in electricity usage by 2020. Rooftop PV must be added to reach a 70 percent reduction. Adding a number of additional PV panels to a planned residential rooftop PV system to reach 100 percent reduction – zero net energy – is straightforward and cost-effective. For this reason, the *Energy Efficiency Strategic Plan* goal is modified in BASE 2020 to a target of 25 percent of residences achieving 100 percent reduction in net electricity usage by 2020. The remaining 75 percent of existing homes will reduce electricity demand by 30 percent through energy efficiency measures by 2020. Multi-family residences will reduce grid demand by 40 percent by 2020, using a combination of energy efficiency and rooftop PV.

BASE 2020 establishes a target of 25 percent of commercial buildings reaching zero net energy by 2020. This is in essence a mid-point target to the *Energy Efficiency Strategic Plan* goal of 50 percent of existing commercial buildings reaching zero net energy by 2030. 75 percent of existing commercial buildings will reduce electricity usage by 30 percent by 2020 using energy efficiency measures. The net effect of achieving these energy efficiency targets will be a reduction of about 30 percent in grid-supplied electricity to homes and commercial buildings in the Bay Area in 2020 compared to the baseline year of 2008.

BASE 2020 also establishes a uniform goal of 2015 for all new homes and commercial buildings to be zero net energy. This uniform goal compares to the *Energy Efficiency Strategic Plan* targets of zero net energy for all new homes by 2020 and for all new commercial buildings by 2030. The BASE 2020 goal is consistent with the goal established by Austin, Texas in 2007, which requires all new homes to be zero net energy capable by 2015.

Industrial plants and agricultural operations would reduce electricity consumption by 25 percent and 15 percent respectively by 2020, consistent with the goals in the *Energy Efficiency Strategic Plan*.

1.3.2 Air Conditioning

Air conditioning is a major source of peak energy demand in the Bay Area. The CPUC estimates air conditioning loads are responsible for more than 30 percent of the total load on hot summer days. BASE 2020 adopts the *Energy Efficiency Strategic Plan* target of a 50 percent reduction in air conditioning loads by 2020. Achieving this peak demand reduction target will reduce Bay Area peak load by over 2,000 megawatts.

Central air conditioning units have an average useful service life of 10 to 14 years. As a result, well over 50 percent of operating central air conditioning units in the Bay Area will be due for replacement by 2020 through normal attrition. Cost-effective state-of-the-art central air conditioning units have less than one-half the electricity demand of typical older operating units. New state-of-the-art units have a much lower electricity demand than new units meeting only the federal minimum efficiency standard.

Incentive funds should be paid at the contractor level to cover the cost difference between a new minimum efficiency unit and a state-of-the-art unit. This would mean that the net price of the most efficient unit offered by heating and ventilation contractors to consumers in the Bay Area is the same as less efficient units. This will ensure that all new units are high efficiency units. Assuming each replacement on average reduces unit electricity consumption by 50 percent, and half the existing units are replaced due to natural attrition in 10 years, the electricity consumption of the entire population of central air conditioning units in the Bay Area will drop about 25 percent over the next decade.

Electronic on/off cycling controls are inexpensive and simple to install. PG&E has a program to install these on/off controls on 25 percent of existing central air conditioning units. Adding cycling controls to all existing and new central air conditioning units will provide the capability to reduce the instantaneous electricity demand from the entire air conditioner population by an additional 30 to 40 percent, as half these units would be in off mode at any given time while the other half are operational.

Conclusions/Recommendations:

- Achieving the energy efficiency targets in BASE 2020 will reduce electricity demand in the Bay Area by approximately 25 to 30 percent in 2020 compared to a 2008 baseline year.
- Air conditioning loads are responsible for at least 30 percent of summer peak loads.
- Incentive funds should be used to cover the cost difference between a minimum efficiency central air conditioning unit and a state-of-the-art unit at the contractor level. This will ensure that all new replacement units are high efficiency units, reducing demand in the units that are replaced by about 50 percent on average.
- Adding cycling capability to all existing and new central air conditioning units will provide the capability to reduce the instantaneous air conditioner electricity demand by an additional 30 to 40 percent.

Sunset Reservoir solar project. Photo: San Francisco Public Utilities Commission

1.4 Independent Clean Energy Alternatives to Achieve BASE 2020

PG&E'S ENERGY EFFICIENCY PROGRAM is not meeting minimum targets established by the CPUC. PG&E is not the ideal entity to lead the effort to achieve the ambitious zero net energy goals in the *Energy Efficiency Strategic Plan* and BASE 2020. In contrast, an independent non-profit organization, the Energy Trust of Oregon, controls public goods funds collected by the Oregon investor-owned utilities for electricity and natural gas efficiency measures and administers programs intended to maximize efficiency gains and rooftop PV. The Energy Trust of Oregon is well regarded by Oregon stakeholders as effective.

The administration of public goods funds by third parties to maximize energy efficiency is a proven concept, as demonstrated by the Energy Trust of Oregon. California also has off-the-shelf regulatory and legislative options that provide for independent pursuit of maximum energy efficiency and rooftop PV. These include Property Assessed Clean Energy (PACE) and Community Choice Aggregation.

1.4.1 – Property Assessed Clean Energy

Berkeley pioneered an innovative, no upfront cost funding mechanism where the city or private investors provide low-interest financing to property owners to pay for energy efficiency improvements and rooftop PV installations. The financing is repaid as property assessments semi-annually with property tax payments. California PACE legislation, AB 811, was passed into law in 2008. Sonoma County has continuously operated a successful residential and commercial PACE program since 2009, the *Sonoma County Energy Independence Program*. This program serves as the model for the privately-financed, $100 million commercial PACE program launched in Sacramento in September 2011. San Francisco launched its commercial PACE program, *GreenFinanceSF-Commercial* in October 2011.

Federal housing corporations Fannie Mae and Freddie Mac indicated in July 2010 that they would not purchase mortgages on properties with PACE assessments. This suspended development of PACE programs, especially residential PACE, in most parts of California and across the country. Lawsuits have resulted in a formal comment procedure at the Federal Housing and Finance Authority, the federal agency that oversees Fannie Mae and Freddie Mac, that may lead to resolution of this controversy. Federal legislation has been proposed to resolve this issue as well. Commercial buildings and homes with no mortgage, which account for about one-third of residential housing stock, are unaffected by the Fannie Mae/Freddie Mac position on PACE assessments.

PACE programs offer a financially manageable mechanism for homeowners and business owners to achieve zero net energy in existing residential and commercial buildings. PACE is independent of utility-funded energy efficiency programs. PG&E does offer a limited on-bill financing program for commercial customers that mirrors the PACE program in numerous respects. A new program, on-bill repayment, is under study. The on-bill repayment program would allow private investors to collect for energy efficiency improvements through PG&E's existing billing process.

1.4.2 – Community Choice Aggregation

California law allows local government to purchase electricity on behalf of their residents and businesses through a mechanism known as Community Choice Aggregation (CCA). A CCA is a public energy authority. CCAs allow more local control of electricity supply, increased renewable energy, and increased local economic benefits from local renewable energy development. The investor-owned utility (PG&E, in the case of the Bay Area) continues to provide transmission and distribution service to CCA customers. Large CCAs serving hundreds of thousands of customers in Ohio and Massachusetts have been operating for a number of years. The Marin Energy Authority launched its CCA program, *Marin Clean Energy*, in May 2010. *Marin Clean Energy* is the state's first operational CCA.

Marin Clean Energy is in the process of expanding its customer base from 14,000 customers to approximately 100,000 customers, as all Marin County residents will have the opportunity to participate in mid-2012. The San Francisco Public Utilities Commission is in the process of launching its CCA program, *CleanEnergySF*, with an initial participation target of 75,000 customers. Sonoma County is considering the formation of a CCA.

CCAs provide some of the services of a public utility. The Bay Area has a number of small public electric utilities. The cost of electric service provided by Bay Area public utilities is consistently 10 to 20 percent or more lower than equivalent service from PG&E. Some of the Bay Area public utilities, most notably Alameda Municipal Power, are achieving substantially higher levels of renewable energy sales than PG&E. Two of the public utilities, Silicon Valley Power and Palo Alto Utilities, offer customers 100 percent renewable energy service at less cost than the standard PG&E tariff for equivalent service. *Marin Clean Energy* now offers its customers options with varying renewable energy content: 25 percent, 50 percent, or 100 percent.

Recent changes to CCA legislation allow the CCA to administer public goods funds collected from CCA customers. These funds have historically been controlled by the investor-owned utility. The CCA can now independently determine how these funds will be used to maximize energy efficiency reductions in the CCA jurisdiction.

1.4.3 – Clean Energy Payments

California has the authority to designate a state agency to establish and administer a clean energy payment program (also known as "feed-in tariff" program), buy the energy at the set payment rates, and require the investor-owned utilities to purchase a specific amount of the electricity generated. The Federal Energy Regulatory Commission (FERC) has acknowledged that a state requirement that investor-owned utilities purchase electricity from a state-owned corporation at specified rates would not be preempted by FERC's authority over wholesale power sales. The state could adopt this approach as an alternative to the CPUC's complex clean energy payment proceedings. CPUC clean energy payment proceedings have consistently resulted in rates that are too low to get either rooftop PV or combined heat and power projects built in quantity.

Conclusions/Recommendations:

- Revival of PACE programs in the Bay Area is necessary to create a dynamic alternative for achieving the goals of BASE 2020. PACE requires little intervention by local or state government to make rapid strides in energy efficiency and rooftop PV.
- CCA offers a viable alternative to Bay Area cities and counties currently served by PG&E to increase local control of electricity supply and increase the contribution of local renewable energy.
- California's Department of General Services has contract expertise and administers the state's revolving loan program under the Energy Efficient State Property Revolving Fund. General Services could serve as the state government entity that sets clean energy payment rates for rooftop PV and combined heat and power, purchases the energy at the set rates, and requires each investor-owned utility to purchase a specific amount of these resources.

1.5 – Rethinking the Grid

1.5.1 – Grid Upgrades

The existing Bay Area distribution grid, without substantial modification, can already absorb the electricity flow from nearly 4,000 megawatts of new local PV that will be added under BASE 2020. Electricity flows in one direction in a conventional grid operation. Safety devices, like circuit breakers, will open if flow is reversed. The cost to retrofit a large distribution substation with smart two-way microprocessor-controlled circuit breakers is low, on the order of several hundred thousand dollars. To realize the full local PV and combined heat and power potential of the distribution grid, two-way flow is necessary.

The California Energy Commission has been advocating that California utilities be required to incorporate smart grid features, including full two-way flow, since 2007. According to its *Smart Grid Deployment Plan 2011-2020,* PG&E is making progress on the necessary grid upgrades. It has installed circuit breakers with full automatic control on over 50 percent of its substations, with a goal of 100 percent conversion by 2015. PG&E is also making other upgrades, such as adding voltage optimization controls on distribution feeders to support high levels of PV generation. With these upgrades, PG&E is largely resolving technical barriers to the rapid development of the Bay Area's full local power potential.

1.5.2 – Fair Financing of Distributed Generation

Local PV systems produce and deliver electricity where it is needed, during high demand daylight hours. As a result, this solar electricity reduces rates to all customers by displacing high cost peaking power, relieving congestion on the electrical grid, reducing wear-and-tear on grid hardware like transformers, and by delaying or eliminating the need to expand the grid.

Achieving the targets in BASE 2020 and the *Energy Efficiency Strategic Plan* will result in nearly a million new solar generators in the Bay Area by 2020. These new generators, who do not currently pay fees to export to the grid, will reduce PG&E grid costs and reduce the need for new distribution grid capital expenditures. Distribution grid costs will drop overall. These cost reductions may equal or exceed the rate that customers with rooftop PV reduce their grid power purchases. In this scenario grid costs will not be shifted to customers without PV, as this smaller group of customers will share a smaller cost.

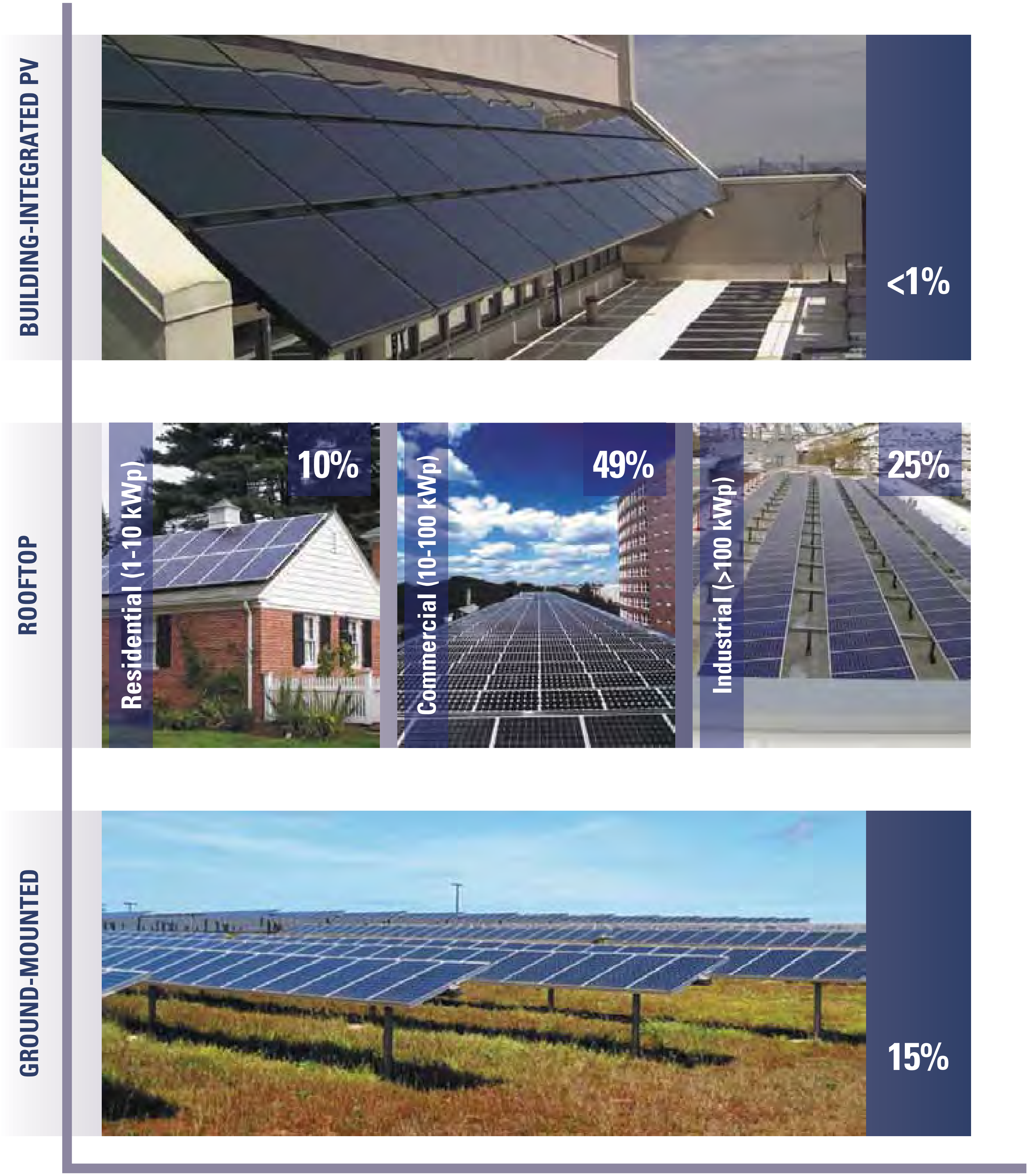
A fair grid cost sharing system is necessary. Historically, financing the building and maintenance of the grid was simple – costs were spread out among all residential, commercial, and industrial customers, and generators paid nothing beyond the initial cost of interconnecting to the grid.

If a thorough and fair review indicates that generators should pay a fee to export electricity to the grid to finance grid costs, then all generators, including large generators that currently pay nothing to export to the grid, should be charged the same fee per kilowatt-hour of exported electricity. Otherwise, utility-scale generators that exclusively export electricity, whether conventional or renewable, would obtain a *de facto* economic advantage over rooftop PV generators while contributing to the grid congestion problem that rooftop PV systems relieve.

1.5.3 – Monitoring Distributed PV

There has been no significant utility effort to date in California to monitor or control the dispatch of non-utility owned rooftop PV on distribution circuits. The monitoring and dispatch control of commercial-scale rooftop PV is considered essential to reliable grid operation in Germany, where approximately 25,000 megawatts of distributed PV is online as of the beginning of 2012 (see graphic, next page). This unnecessary "blindness" can lead to grid reliability issues during certain weather and load conditions. One simple step that needs to be taken by PG&E and other California utilities is to monitor and control the dispatch of commercial-scale rooftop PV owned by third parties.

Solar Market Segments, Germany, 2010



Photos: National Renewable Energy Laboratory, Photographic Information eXchange
Source: Statistics of the Federal Network Agency, BSW-Solar Estimates Shares according to installed capacity.

1.6 Displacement of Fossil Fuel Generation by BASE 2020

A SIGNIFICANT SOURCE OF PG&E'S GHG EMISSIONS is from power purchased on the wholesale power market and identified as "unspecified" in the 2009 PG&E power mix. These power purchases include coal. BASE 2020 will displace all coal usage over the next decade with baseload combined heat and power, increased geothermal output from existing plants at The Geysers, and the integration of battery storage with existing wind power in Solano County.

The second source of PG&E coal power purchases is long-term contracts with a few California coal-fired co-generation plants. BASE 2020 will displace these sources over the next decade, and replace them with the same clean baseload resources to be used to displace PG&E imported coal power purchases.

PG&E is proposing to contract for over 2,000 MW of new natural gas-fired gas turbine plants to be built in the Bay Area over the next few years. The expense of having this new gas turbine capacity available will be on the order of $600 million per year for 20 years. This is despite high electricity reserve margins in the range of 30 to 40 percent, that assure grid reliability on hot days when electricity use is highest. Actual reserves margins are much higher than the required 15 to 17 percent, and indicate that PG&E already has an excess of generation available to meet any reasonably foreseeable demand without new gas-fired plants. There has been no growth in peak demand in recent years that would justify adding more peaking capacity.

A primary justification for these new turbines, offered by PG&E and the California Independent System Operator, is the need to back-up solar and wind resources. Solar PV is completely reliable on hot summer afternoons when peak loads occur in the Bay Area. There is no significant cloud cover during the hottest hours of the summer when the highest electricity demand occurs.

A second justification offered is the need to retire once-through cooled steam boiler plants in the Bay Area due to their impact on marine life. PG&E has identified only two once-through cooled steam boiler units in its service territory, located in Pittsburg, as necessary for Bay Area grid reliability. It would be much cheaper and more efficient to retrofit these existing boiler plants to cooling towers and use them as a back-up peak power supply for another decade or two, than to build new gas turbine plants that will be in operation for 50 years.

Conclusions/Recommendations:

- BASE 2020 will rapidly drive down demand for grid power, obviate the need for any new utility-scale natural gas plants, and end any reliance on coal power.
- Actual PG&E reserve margins are considerably higher than necessary to assure grid reliability on hot days. Peak demand has been static or declining in recent years. Peak loads will steadily decline if BASE 2020 is implemented.
- Solar PV is completely reliable on hot summer afternoons when peak loads occur in the Bay Area. There is no significant cloud cover during these periods. There is no reliability need to build peaking gas turbines to back-up PV in anticipation of significant cloud cover on the hottest days.
- The cost of retrofitting wet cooling towers at the power plant in Pittsburg to eliminate the marine impacts of once-through cooling would be much lower than building new gas turbine peaking capacity to replace these units.
- The $600 million per year of PG&E ratepayers will pay for four new gas turbine power plants in the Bay Area would be sufficient to pay for more than half of the nearly 4,000 MW of new local PV, at 2012 PV prices, that will be added in the Bay Area under BASE 2020.

1.7 Ratepayer Benefits from BASE 2020

THE REDUCTION OF DEMAND FOR PG&E-SUPPLIED electricity and natural gas, achieved through energy efficiency measures, PV, combined heat and power, geothermal, wind, and solar hot water, also reduces the price of electricity and natural gas in wholesale energy markets. This is known as the "merit order effect." It reduces the cost of electricity and natural gas for all ratepayers.

The merit order effect of distributed generation in Germany, an electricity market two times the size of the California market, reduced the wholesale electricity price to German customers by approximately $5 billion in 2009.

PG&E buys a significant amount of electricity and natural gas from wholesale markets. The market price benefits of reduced demand caused by energy efficiency measures and local clean energy will substantially outweigh the transaction costs, especially interconnection costs, that currently hamper or prevent the deployment of local PV and combined heat and power projects.

Conclusions/Recommendations:

- The merit order benefit of distributed PV and combined heat and power on wholesale electricity prices is substantially greater than the transaction costs, especially interconnection costs, imposed by PG&E on distributed PV and combined heat and power developers. These transaction costs should be absorbed by PG&E as the net economic benefit to all PG&E customers of having these PV and combined heat and power systems online substantially outweighs the transaction costs.
- This same merit order benefit applies to natural gas demand reduction realized by use of combined heat and power, solar hot water heating, and substitution of biomethane or biogas for pipeline natural gas. Payments for these technologies and fuels must incorporate the value of the merit order benefit to assure that the deployment of technologies and fuels that are bringing net price benefits to all natural gas consumers are not inappropriately constrained by inadequate incentive budgets.
- The California Energy Commission should verify the merit order effect of the energy efficiency and distributed generation targets in BASE 2020 on the wholesale market price of electricity. The results of this verification would serve as the basis for increasing funding for energy efficiency and demand response programs and for shifting all distributed generation transaction costs, including interconnection costs, to PG&E ratepayers.
- The California Energy Commission should conduct a similar verification of the merit order effect of the BASE 2020 targets for combined heat and power, solar hot water heating, and natural gas substitution with biogas and biomethane on the wholesale market price of natural gas. The results would serve as the basis for increasing incentives for solar hot water systems and biogas and biomethane fuel production.

1.8 GHG Reductions Achieved by BASE 2020

ACHIEVING BASE 2020 TARGETS WILL RESULT IN A reduction of more than 60 percent in Bay Area GHG emissions from electricity usage by 2020. Peak demand on the grid will decline by more than 50 percent.

Table 1-1 summarizes estimated 2008 GHG emissions from electricity usage in the Bay Area. The term GHG is used interchangeably with carbon dioxide (CO_2) in BASE 2020.

Table 1-1. Total Bay Area GHG Emissions from Electricity Consumption in 2008

Source	GWh[3]	CO_2 emission factor (tons/MWh)	2008 CO_2 emissions (million tons)	Bay Area fraction	2008 Bay Area CO_2 emissions (million tons)
PG&E bundled customers	81,983	0.32	26.2	0.6	15.7
PG&E Direct Access customers	6,376	0.48	3.1	0.6	1.8
Bay Area public utilities	5,327	0.32	1.7	1.0	1.7
				Bay Area total	**19.2**

Table 1-2. CO2 Reduction Achieved by Implementing BASE 2020

Source of CO_2 reduction	Quantity of reduction (GWh)	CO_2 emissions (million tons)	Fuel type displaced	Avoided CO_2 emissions (million tons)	Net CO_2 reduction (million tons)
Energy efficiency	15,448	0	natural gas	4.9	4.9
Rooftop PV	6,799	0	natural gas	3.4	3.4
Combined Heat and Power	6,770	1	imported	3.2	2.2
New geothermal	2,234	0	imported	1.1	1.1
New wind with energy storage	867	0	imported	0.4	0.4
Total reduction					**12.0**

Table 1-2 summarizes the actions to be taken in BASE 2020 to reduce GHG emissions and the GHG reductions achieved. Net GHG emissions from electricity usage would decline from 19 million tons per year in 2008 to 7 million tons per year in 2020, a reduction of more than 60 percent.

The Bay Area peak load reductions on PG&E and Bay Area public utility systems that would occur as a result of BASE 2020 are shown in Table 1-3. Electricity purchased from Bay Area utilities would decline at peak from about 14,000 megawatts in 2008 to approximately 6,500 megawatts in 2020.

This is more than a 50 percent reduction in the peak demand met with grid power. The majority of the reduction in peak demand for utility-supplied grid power will come from energy efficiency measures in general, as well as from more efficient central air conditioners and commercial building chiller plants.[3] The remaining peak demand reduction on the grid will be demand displacement by rooftop PV, combined heat and power, and battery storage.

Table 1-3. Bay Area Peak Load Reduction Achieved by Implementing BASE 2020

Source of reduction	Basis of reduction (MW)	Peak load reduction (MW)
Energy efficiency	25 percent reduction in demand on average from energy efficiency measures	2,500
Air conditioner/ chiller plant efficiency improvement	Cooling load represents about 30 percent of peak load. Highest efficiency central air conditioning (CAC) units replace worn-out units, 50 percent reduction. 50 percent reduction targeted for commercial building chiller plants. Cycling capability built into new CAC units to allow 50 percent online, 50 percent offline at peak. A 50 percent turnover in CAC population is assumed.	2,100
Rooftop PV	3,800 MWac of rooftop PV added by 2020. 50 percent of this capability, 1,900 MWac, is available at peak.	1,900
Battery storage associated with rooftop PV	200 megawatts of battery storage will be added to residential and commercial Bay Area buildings to absorb mid-day PV output, provide peaking capacity, address the intermittency of solar electricity production, and serve as the foundation of community-scale microgrids that can operate around-the-clock on electricity supplied by rooftop PV.	200
Combined heat and power	840 MW of combined heat and power is added to Bay Area, removing equivalent amount of load from utility demand at peak.	840
	Total Bay Area peak load reduction	**7,540**

BILL POWERS, P.E.

Mr. Powers is a registered professional mechanical engineer in California with over 25 years of experience in the energy and environmental fields. He is the author of the 2007 strategic energy plan, "San Diego Smart Energy 2020," for the San Diego region. The plan uses California's Energy Action Plan as the template for accelerated introduction of local distributed renewable and combined heat and power resources to reduce greenhouse gas emissions from power generation in the San Diego region by 50 percent by 2020. Mr. Powers served as an expert witness in a landmark California Energy Commission proceeding where the Commission determined urban solar photovoltaics could potentially serve as a cost-effective alternative to conventional gas turbine peaking power. He has written numerous articles on the strategic cost and reliability advantages of local renewable energy over large-scale, remote, transmission-dependent renewable resources.

Mr. Powers began his career converting Navy and Marine Corps shore installation power plants from oil-firing to domestic waste, including woodwaste, municipal solid waste, and coal, in response to concerns over the availability of imported oil following the Arab oil embargo. He has permitted numerous peaking gas turbine, microturbine, and internal combustion engine cogeneration plants in California. Mr. Powers organized the first U.S. conference focused exclusively on dry cooling systems for power plants in 2002. Mr. Powers currently serves on the San Diego Environmental and Economic Sustainability Task Force. The mission of the task force is to produce a Climate Mitigation and Adaptation Plan for San Diego. Mr. Powers has a B.S. in mechanical engineering from Duke University and an M.P.H. in environmental sciences from the University of North Carolina—Chapel Hill.

(Endnotes)

1 The California *Energy Efficiency Strategic Plan* target of 25 percent of residences reaching 70 percent reduction in electricity usage by 2020, compared to a 2008 baseline, is modified in BASE 2020 to 25 percent of residences achieving 100 percent reduction in electricity usage by 2020. The *Energy Efficiency Strategic Plan* target of 50 percent of existing commercial buildings reaching net zero energy by 2030 is expanded in BASE 2020 to establish a target of 25 percent of commercial buildings reaching net zero energy by 2020.

2 Commercial PV is eligible for accelerated depreciation.

3 "Management" in this case refers to widespread adoption of air conditioner cycling as a peak load reduction measure

2. California's Energy Strategy

2.1 Energy Action Plan & Energy Efficiency Strategic Plan

The *Energy Action Plan* establishes the electricity resource priority list, or loading order, that defines how California's energy needs are to be met. *Energy Action Plan I* was published in May 2003.[1] The CEC and the California Public Utilities Commission (CPUC) developed the *Energy Action Plan* to guide strategic energy planning in California. The loading order is summarized in Table 2-1.

Table 2-1. Energy Action Plan Loading Order

1. Energy efficiency, including onsite renewable generation, and demand response
2. Renewable energy
3. Combined heat and power
4. Utility-scale natural gas-fired generation
5. Transmission (as needed to support other elements)

The *Energy Action Plan* is explicit that rooftop PV is an element of energy efficiency standards for new buildings. *Energy Action Plan I* states, "Incorporate distributed generation or renewable technologies into energy efficiency standards for new building construction."

The CEC's December 2009 *Integrated Energy Policy Report* (IEPR) underscores the integration of energy efficiency and rooftop PV as the primary elements of zero net energy (ZNE) buildings, explaining:[2]

> With the focus on reducing GHG emissions in the electricity sector, energy efficiency takes center stage as a zero emissions strategy. One of the primary strategies to reduce GHG emissions through energy efficiency is the concept of zero net energy buildings. In the 2007 IEPR, the Energy Commission recommended increasing the efficiency standards for buildings so that, when combined with on-site generation, newly constructed buildings could be zero net energy by 2020 for residences and by 2030 for commercial buildings.
>
> A zero net energy building merges highly energy efficient building construction and state-of-the-art appliances and lighting systems to reduce a building's load and peak requirements and includes on-site renewable energy such as solar PV to meet remaining energy needs. The result is a grid-connected building that draws energy from, and feeds surplus energy to, the grid. The goal is for the building to use net zero energy over the year.

California's *Energy Efficiency Strategy Plan* was developed through a formal CPUC regulatory process, approved in September 2008, and updated in January 2011.[3] An objective of the CPUC in directing the investor-owned utilities (IOUs) to develop the *Energy Efficiency Strategic Plan* was to evolve the *Energy Action Plan* policy guidelines into regulatory goals with timelines.[4] The goals in the *Energy Efficiency Strategic Plan* are listed in Table 2-2:[5]

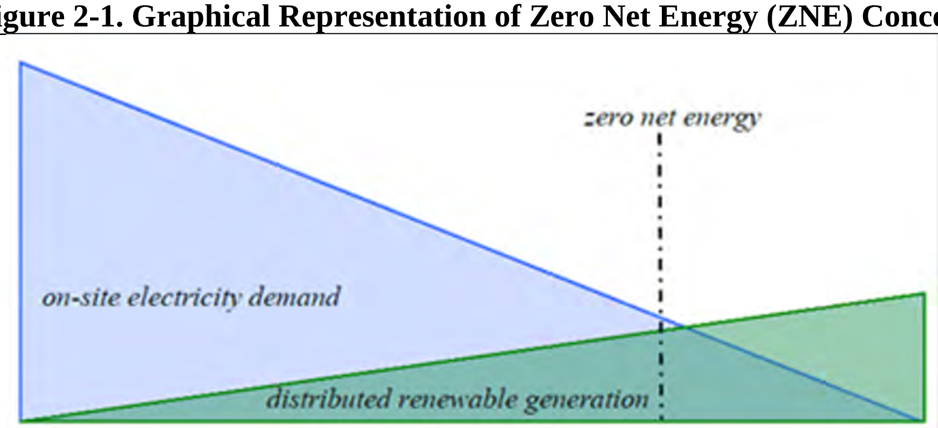
Table 2-2. Energy Efficiency Strategic Plan Goals

	Goal	Target year (2008 baseline)
1.	All new residential construction is zero net energy (ZNE)	2020
2.	25 percent of existing single-family homes achieve 70 percent decrease in purchased energy	2020
3.	75 percent of existing residential achieves 30 percent decrease in purchased energy	2020
4.	100 percent of multi-family housing achieves a 40 percent decrease in purchased energy	2020
5.	All new commercial construction is ZNE	2030
6.	50 percent of existing commercial buildings achieve ZNE	2030
7.	Industrial facilities will reduce energy intensity by 25 percent	2020
8.	Agricultural operations will reduce production energy intensity by 15 percent	2020
9.	50 percent improvement in efficiency in the heating, ventilation, and air conditioning sector	2020
10.	75 percent improvement in efficiency in the heating, ventilation, and air conditioning sector	2030

Energy efficiency measures and rooftop PV are integral components of the *Energy Efficiency Strategy Plan*. The use of rooftop PV is necessary for a building to achieve near ZNE or ZNE status.[6] Rooftop PV is a subset of distributed PV. Distributed PV is generally defined as any PV system less than 20 MW that interconnects at a distribution voltage level less than 69 kV.

Rooftop PV can be added rapidly in large quantity with the right regulatory framework. Germany, which is approximately the same size as California and which has about double the electricity demand, added 7,400 MW_{dc} of distributed PV in the 2010.[7] The country added another 7,500 MW_{dc} in 2011.[8] More than 3,000 MW_{dc} of this capacity was added in one month, December 2011.[9] Over four-fifths of this capacity is rooftop PV.[10] The concept of ZNE is shown graphically in Figure 2-1.

Figure 2-1. Graphical Representation of Zero Net Energy (ZNE) Concept



2.2 State Energy Policy Direction

California experimented with electricity deregulation in the 1996 – 2003 timeframe. The IOUs opted to sell off most of their generation assets, with the principal exception of the Diablo Canyon and San Onofre nuclear plants, and become "wires only" transmission and distribution (T&D) companies. Electricity was purchased by the IOUs on the open market for residential and commercial customers. Larger commercial and industrial customers were permitted to bypass the IOUs and purchase electricity directly from third party energy service providers. These customers are known as Direct Access customers.

Extensive market manipulation in 2000 – 2001 resulted in huge price spikes, blackouts, and an end to deregulation. The state signed high cost, long-term contracts with numerous electricity generators in 2001 as part of a suite of actions to address the immediate crisis. These contracts were assigned to the Department of Water Resources (DWR). Many of these contracts expired in 2011 or will expire in 2012. The California legislature and the CPUC ended the expansion of Direct Access in 2001.

Responsibility for long-term planning was returned to the IOUs in 2003. What has emerged in the intervening years is a hybrid market consisting IOU-owned generation and third party generation.[11] One complicating factor of this hybrid approach is that customers interested in leaving IOU service are subject to substantial departing load charges to cover the cost of new IOU power plants or new long-term supply contracts between the IOU and third parties.

The Renewable Portfolio Standard (RPS) of was first mandated in 2002 and set an RPS target of 20 percent of retail electricity sales by 2017 for the IOUs. In 2006, the 20 percent target date was accelerated to 2010.[12] Former Governor Schwarzenegger signed an executive order in 2008 setting a new RPS target of 33 percent by 2020. The California legislature passed a RPS bill in 2009 that would have revised the RPS target to 33 percent by 2020, but it was vetoed by former Governor Schwarzenegger due to concerns about the limits placed on the use of out-of-state renewable generation.[13] The legislature failed to pass a bill in the 2010 legislative session. The legislation was re-introduced in December 2010 as SB 2 (1X) and signed into law on April 12, 2011.[14] The IOUs have to date relied to a large degree on remote utility-scale renewable energy projects to meet the RPS mandate.

California's AB 32 climate action legislation, the *California Global Warming Solutions Act*, was passed into law in 2006. AB 32 mandates that California reduce greenhouse gas (GHG) emissions to 2000 levels by 2010, to 1990 levels by 2020, and reach 80 percent below 1990 levels by 2050.[15]

The California Air Resources Board (CARB) is the lead agency tasked with implementing AB 32. The December 2008 *AB 32 Scoping Plan* developed by CARB proposed the following targets related to energy: 1) reduce demand by 32,000 GWh via energy efficiency measures, 2) add 4,000 MW of combined heat and power (CHP) to displace 30,000 GWh of conventional generation, 3) reduce natural gas consumption by 800 million therms via energy efficiency measures, 4) add 200,000 solar hot water heaters in compliance with AB 1470, 5) achieve a 33 percent RPS by 2020, 6) achieve one million solar roofs, 3,000 MW, by 2017, and 7) implement a CO_2 cap-and-trade program.[16]

The *AB 32 Scoping Plan* also states that "zero energy new and existing buildings can be an overarching and unifying concept for energy efficiency in buildings."[17] As noted, the *Energy Efficiency Strategic Plan* focuses on achieving zero net energy consumption in residential and commercial buildings through energy efficiency measures and use of rooftop PV.[18]

Community Choice Aggregator (CCA) legislation granting California cities and counties the option to provide electricity supply within their political jurisdiction was passed in 2002. The IOU remains responsible for T&D in the CCA framework. The Marin Energy Authority (MEA) launched the first operational CCA program in California, *Marin Clean Energy*, in 2010. San Francisco is in the process of launching its CCA program, *CleanPowerSF*.

Bay Area cities have been leaders in building efficiency. San Francisco adopted the *Green Building Ordinance* for new buildings in 2008.[19] Berkeley for over two decades has had residential and commercial building ordinances requiring basic efficiency improvements, triggered at the time of property sale or significant renovations.[20]

Berkeley pioneered an innovative, no upfront cost funding mechanism where the city provides low-interest loans to property owners to finance energy efficiency improvements and rooftop solar installations, with long-term repayments added to their annual property tax bills. AB 811, *Property Assessed Clean Energy* (PACE), passed into law in California in 2008, made this financing mechanism available statewide.

Resistance by federally-backed mortgage companies Fannie Mae and Freddie Mac has temporarily suspended development of PACE programs in the state and across the country. Then-Attorney General Jerry Brown sued Fannie Mae and Freddie Mac over their rejection of PACE assessments in July 2010.[21] The lawsuit is ongoing. PACE programs offer a mechanism for homeowners and business owners to achieve net zero energy consumption without spending money upfront.

Governor Jerry Brown proposes through his *Clean Energy Jobs Plan* that a majority of the new renewable energy resources to be built in the state by 2020, 12,000 MW out of a total of 20,000 MW, be local renewable power.[22] Approximately 3,000 MW of energy storage would be added to the grid to meet peak demand and support renewable energy generation.[23] The *Clean Energy Jobs Plan* also calls for the addition of 6,500 MW of new CHP over the next 20 years and a substantial improvement in the energy efficiency of new and existing buildings.

IOUs provide approximately 65 percent of the retail electricity consumed in California. Statewide publicly-owned utilities (POUs) provide approximately 25 percent.[24] POUs in the Bay Area include City of Healdsburg, Port of Oakland, Alameda Municipal Power (AMP), Silicon Valley Power (SVP), City of Palo Alto Utilities (CPAU), San Francisco Public Utilities Commission (SFPUC), and Bay Area Rapid Transit (BART). Direct Access electricity providers, such as Constellation NewEnergy, Calpine PowerAmerica, and Shell Energy supply the remaining 10 percent. A number of the Bay Area POUs are leaders in renewable energy and low-cost electricity supply.

2.3 Investor-Owned Utility Business Model

PG&E is an IOU. An IOU earns a fixed profit based on the value of the property it owns through a mechanism called “ratebasing.” Ratebasing allows IOUs to recover investments through rates charged to customers. The CPUC regulates whether or not a proposed project may be ratebased. Examples of such investments are IOU-owned power plants, T&D lines, and IOU-owned electric and gas meters. In other words, the more an IOU invests in such projects, the more money it earns.

No changes were made to the CPUC's existing ratebasing policies to align investments when the CPUC, the CEC, and the Legislature adopted the *Energy Action Plan* and its associated loading order in 2003. As a result, the IOUs do not currently have a compelling economic incentive to support the loading order, which prioritizes energy efficiency reductions and rooftop PV.[25,26]

The CPUC's ratebasing policies have evolved over the last 100 years. The primary type of proceeding where ratebasing policies are addressed is the general rate-setting case. The regulated utility model, used in California up until the 1996 restructuring experiment, called for IOUs to invest shareholder funds in capital projects and to be allowed to recover those costs in rates charged to the ratepayers, along with a rate-of-return (profit) set by the CPUC.

The tendency of the traditional ratemaking formula to encourage over-investment in utility capital projects is well known. Until 1981, California IOUs were focused on building revenues by convincing customers to use more electricity and natural gas, as the IOUs had more capacity than needed to serve customer load. The IOUs spent money on marketing to get customers to use more electricity and natural gas. This included promoting all-electric "gold medallion" homes to increase electric demand, and promotions with rebates and discounts to get customers to buy more electric and gas appliances.

2.4 Reality of State Energy Development

> “*There’s an ongoing schizophrenia in state policy between what we say we want to do and what we actually allow to happen*.” - former California Energy Commission (CEC) Commissioner John Geesman[27]

The California *Energy Action Plan* forms part of the framework of BASE 2020. On paper, support for the *Energy Action Plan* is unanimous. Fidelity to the *Energy Action Plan* is stated in virtually every state energy agency planning document and every application by the state’s IOUs for conventional infrastructure projects, including natural gas-fired generation and new transmission.

No fundamental redesign of IOU financial incentives accompanied development of the *Energy Action Plan*. For the last century that IOU model has remained relatively unchanged – IOUs are the sole source supplier of vertically integrated electricity generation, transmission, and distribution services.

As a result California energy policy operates in two parallel universes – all actors express support for the *Energy Action Plan* in concept, while finding avenues to continue and even expand the status quo. The IOU business model is continues to be based on private monopoly control of generation, transmission, and distribution of electricity. New revenue continues to be generated by steel-in-the-ground projects owned by the IOU.

Today, the IOUs continue to build and contract for utility-scale natural gas fired plants, remote utility-scale solar and wind plants, and the transmission lines necessary to reach them, while publicly acknowledging the merits of energy efficiency, rooftop PV, and CHP. The current business reality is that energy efficiency measures, and onsite generation owned by customers in the form of rooftop PV or CHP, undercut the justification for an IOU to build more infrastructure.

3. Bay Area Energy – The Players

3.1 Geographic Scope

BASE 2020 addresses the nine counties surrounding San Francisco Bay. These counties include Alameda, Contra Costa, Marin, Napa, San Francisco, San Mateo, Santa Clara, Solano, and Sonoma. The location of the nine Bay Area counties within PG&E service territory is shown in Figure 3-1.

Figure 3-1. Map of PG&E Service Territory and Nine Bay Area Counties[28]

3.2 Electricity Demand in PG&E Service Territory

Electric power demand is measured in two ways for resource planning purposes: 1) total electric energy usage over the course of a year, and 2) peak power demand during hot summertime conditions. Annual energy usage is analogous to the total gallons of fuel used by an automobile over the course of a year. Peak power demand is analogous to the maximum horsepower required of the automobile when it is fully loaded and must maintain a high rate of speed while driving up a hill. Electricity planning in California is largely guided by peak power demand.

Table 3-1 shows the current trend in annual and hourly energy consumption in PG&E service territory. There was a significant dip in demand in 2009 relative to 2008. The primary reason for this reduction in demand was the economic slowdown that began in late 2008.

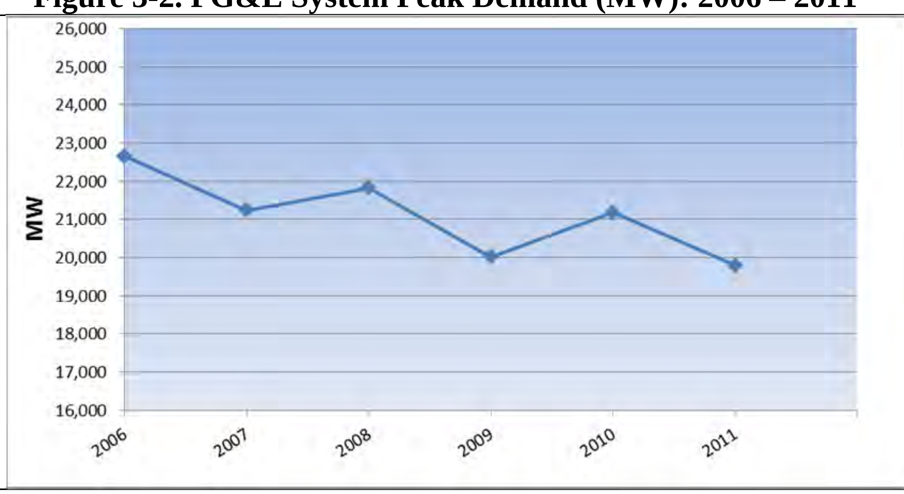
Table 3-1. PG&E Annual and Average Electricity Demand Trends[29]

Demand type	2008	2009
Annual energy demand in PG&E service territory, GWh per year	88,359	85,459
Average hourly demand in PG&E service territory, MW	10,087	9,756

The highest peak one-hour electricity demand in PG&E service territory, 22,650 MW, occurred in 2006.[30] This peak took place during a record-setting heat storm in California. PG&E estimates that the temperature conditions that led to this peak demand represented a 1-in-30 to 1-in-40 year occurrence.[31] Peak demand is primarily associated with heavy usage of air conditioning systems on hot summer afternoons.

The peak demand trend over the 2006 – 2011 timeframe in PG&E service territory is shown in Figure 3-2. The 2011 peak load, 19,791 MW, was nearly 3,000 MW lower than the 2006 peak load.[32] PG&E had ample resources to meet the record peak load in 2006 without dropping below the minimum Western Electricity Coordinating Council operating reserves requirement of 6 to 7 percent.[33] A substantial number of gas turbine peaker units are located in the Bay Area to assist in meeting peak demand. More are proposed for construction despite a declining peak load trend.

Figure 3-2. PG&E System Peak Demand (MW): 2006 – 2011[34,]



3.3 Electricity Demand in Bay Area Counties

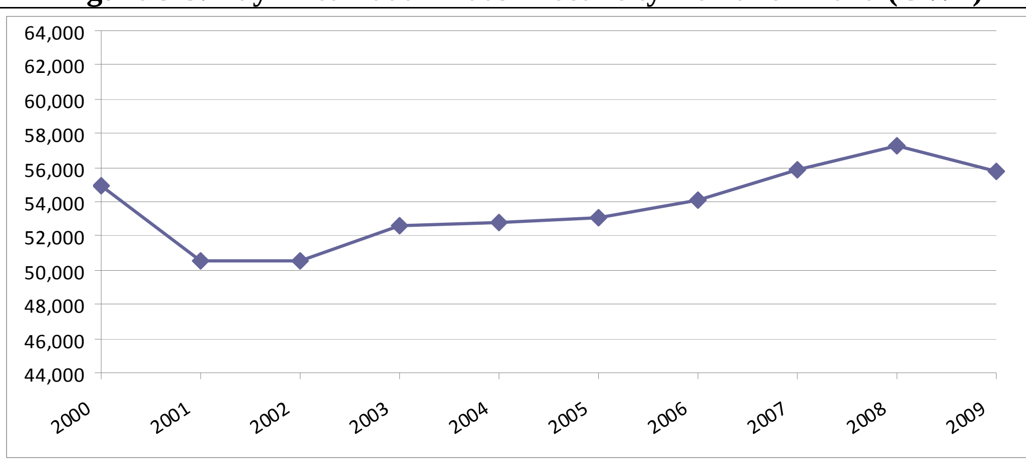
Collectively these nine counties account for approximately half of the electricity demand in the PG&E planning area. 2009 electricity consumption in the Bay Area counties was 55,817 GWh as shown in Table 3-2.[35] The total consumption in the PG&E planning area was 106,531 GWh in 2009.[36] The PG&E planning area includes all POUs in PG&E service territory except Sacramento Municipal Utility District (SMUD).

Table 3-2. 2000 – 2009 Electricity Consumption (GWh) in Nine Bay Area Counties

County	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Annual Growth (%)
Alameda	10,488	9,948	10,305	10,642	10,577	10,921	11,098	11,864	11,682	11,535	1.0
Contra Costa	8,849	8,455	8,438	8,600	8,496	8,422	8,511	8,606	9,014	8,660	-0.2
Marin	1,486	1,347	1,399	1,373	1,418	1,392	1,412	1,407	1,482	1,482	0.0
Napa	937	849	885	912	931	932	962	957	1,038	1,006	0.7
San Francisco	5,522	5,346	5,407	5,220	5,242	5,711	5,515	5,586	5,694	5,550	0.1
San Mateo	4,943	4,137	4,133	4,742	4,824	4,511	4,629	4,917	5,116	4,961	0.0
Santa Clara	16,667	15,150	14,383	15,343	15,441	15,396	16,025	16,387	17,088	16,559	-0.1
Solano	3,108	2,717	2,828	3,004	3,035	3,045	3,090	3,317	3,232	3,210	0.3
Sonoma	2,890	2,586	2,735	2,758	2,863	2,756	2,842	2,847	2,970	2,853	-0.1
Total	54,890	50,535	50,513	52,593	52,828	53,085	54,082	55,887	57,316	55,817	0.2

The average annual electricity demand growth in the Bay Area in the 2000 to 2009 time period was 0.2 percent per year. The Bay Area electricity demand growth trend is shown in Figure 3-3.

Figure 3-3. Bay Area 2000 – 2009 Electricity Demand Trend (GWh)



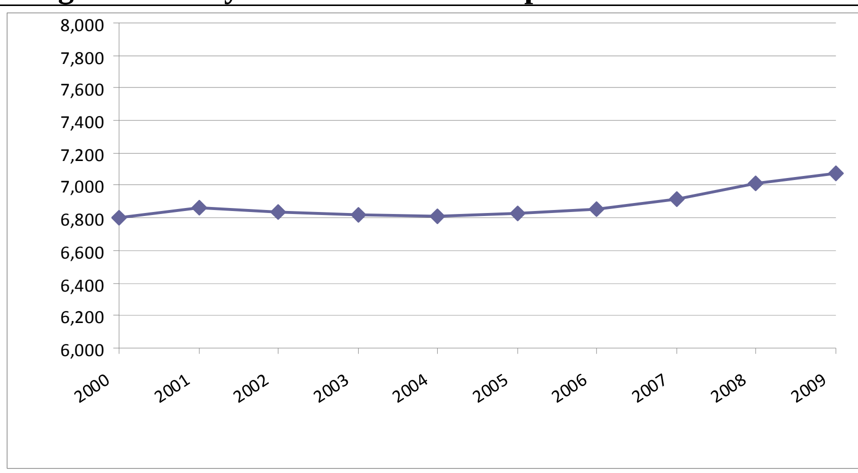
Population in the nine Bay Area counties grew at an average annual rate of 0.4 percent per year from 2000 through 2009.[37] The population data for each Bay Area county is provided in Table 3-3.

Table 3-3. 2000 – 2009 Population Growth in the Nine Bay Area Counties

County	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Annual Growth (%)
Alameda	1,450	1,469	1,460	1,451	1,441	1,436	1,438	1,448	1,467	1,480	0.2
Contra Costa	953	971	980	988	993	1,000	1,002	1,010	1,025	1,036	0.9
Marin	248	248	246	245	244	244	244	246	248	249	0.0
Napa	125	127	128	130	130	130	130	131	133	134	0.8
San Francisco	777	784	778	773	771	775	783	796	805	810	0.4
San Mateo	708	707	699	695	693	693	694	699	709	714	0.1
Santa Clara	1,686	1,691	1,673	1,668	1,670	1,684	1,701	1,725	1,756	1,771	0.5
Solano	397	404	408	408	408	406	405	405	406	411	0.3
Sonoma	460	464	463	463	463	461	459	460	465	470	0.2
Total	6,805	6,864	6,836	6,821	6,812	6,828	6,857	6,920	7,013	7,074	0.4

A graphical presentation of Bay Area population growth from 2000 through 2009 is provided in Figure 3-4.

Figure 3-4. Bay Area 2000 – 2009 Population Growth Trend



PG&E projected an annual growth in peak electricity demand of 2.1 to 2.7 percent per year for the 2007-2016 timeframe in its *2006 Long-Term Procurement Plan*.[38] A peak demand growth rate of 1.7 percent per year was projected by the CEC over the same period.[39] This peak demand growth rate projection was made before the economic recession began in late 2008. The CEC projects a peak demand growth rate of 1.3 percent per year in its California electricity demand forecast for the 2010 to 2020 period published in December 2009.[40] An aging population is the primary reason cited by the CEC for a lower population growth rate in 2010 – 2020 compared to the previous decade and therefore a lower peak electricity demand growth rate.[41]

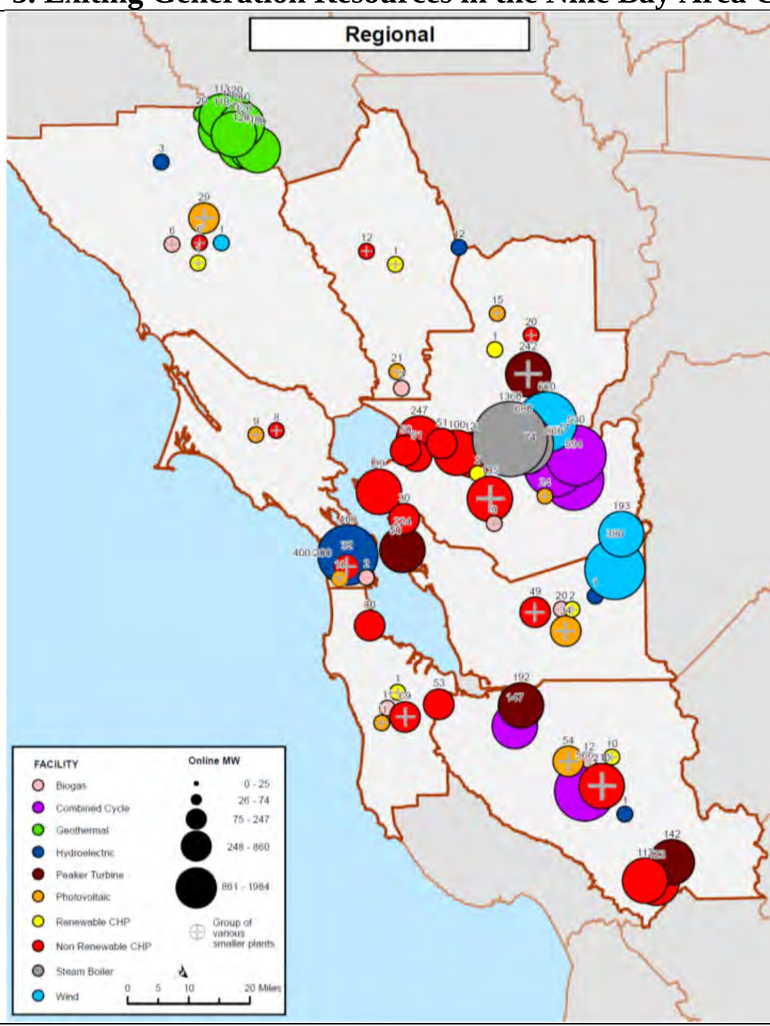
The U.S. Census population growth rate for counties in PG&E service territory for the period 2000 – 2009 was 0.9 percent.[42,43] The 2000 – 2009 population growth by county in PG&E territory is provided in Appendix A. As noted, the Bay Area population growth rate during the same period was 0.4 percent, and the electricity demand growth rate was 0.2 percent.

Four conclusions can be drawn from a comparison of actual data to the PG&E and CEC projections: 1) the assumption that electricity demand will increase linearly with population demand may not be valid, as electricity demand may be increasing at a slower rate than population growth, 2) the actual PG&E service territory population growth rate of 0.9 percent per year in the 2000 – 2009 period is substantially less than either the PG&E projected peak demand growth rate of 2.1 to 2.7 percent or the more recent CEC projected peak demand growth rate of 1.3 percent per year, 3) the population growth rate in the 2010 – 2020 period should be less than the population growth rate in the previous decade due to an aging population, and as a result, 4) the electricity demand growth rate should be no more than the actual 2000 – 2009 actual population growth rate and potentially less.

3.4 Existing Generation Resources in the Bay Area

Figure 3-5 is a map of the existing generation sources in the nine-county Bay Area. Circles with a "+" symbol represent an aggregate of multiple smaller sources. A PG&E Bay Area substation map and maps of generation sources in each Bay Area county are provided in Appendix B.

Figure 3-5. Exiting Generation Resources in the Nine Bay Area Counties[44]



Note: Blue hydroelectric icon in San Francisco represents dedicated Hetch Hetchy supply: 400 MW peak, 200 MW average.

Table 3-4 summarizes the existing generation sources in the nine-county Bay Area. The data on generator type and quantity provided in Table 3-4 for each county serves as the input for Figure 3-5. The data in Table 3-4 is current through January 2011.

Table 3-4. Type and Quantity (MW) of Existing Generation in the Bay Area[45]

County	Steam Boiler	Combined Cycle	Peaking Turbine	CHP	PV	Wind	Geo-thermal	Hydro	Renewable CHP[a]
Alameda			273	79	34	380		1	22
Contra Costa	2,040	1,984	47	1,038	24	193			11
Marin				8	9				
Napa				12	21			12	3
San Francisco				32	11			400[b]	2
San Mateo				99	11				11
Santa Clara		713	334	498	54			1	22
Solano			242	65	15	660			
Sonoma				3	29		1,158	3	6
Total:	2,040	2,697	896	1,834	208	1,233	1,158	417	77

a) Renewable CHP includes CHP units using biogas or biomethane as fuel.
b) This hydroelectric capacity represents dedicated Hetch Hetchy supply to San Francisco: 400 MW peak, 200 MW average.

3.5 Bay Area Electricity Providers

The Bay Area includes a wide mix of electricity providers. These include the POUs Alameda Municipal Power (AMP), City of Palo Alto Utilities (CPAU), San Francisco Public Utilities Commission (SFPUC), and Silicon Valley Power (SVP), the Marin County CCA Marin Energy Authority (MEA), energy service providers like Shell and Constellation Energy, and PG&E.

POUs are non-profit public providers of electric supply, and T&D services for a specific political or governmental jurisdiction. CCAs are non-profit public providers of electricity supply only. T&D services for the CCA are provided by the IOU. IOUs are private monopolies with shareholders. Energy service companies provide electricity directly to utilities, CCAs, and some commercial customers participating in the Direct Access program.

3.5.1 Bay Area Publicly-Owned Utilities (POUs)

The total amount of electricity delivered by PG&E in 2009 was 85,459 GWh.[46] Of this total, 50,681 GWh was delivered to PG&E bundled and Direct Access customers in the Bay Area.[47]

There are also six POUs in the nine Bay Area counties that deliver electricity to customers. The total amount of electricity delivered by these six Bay Area POUs in 2008 was 5,136 GWh. The total electricity delivered to all Bay Area customers in 2009 was 55,817 GWh. The POUs are described in Table 3-5. A map of the location of the Bay Area POUs is provided in Appendix C.

Table 3-5. Publicly-Owned Utilities in the Nine Bay Area Counties

Name	Electricity Deliveries[48] (2009 GWh)	Description of Generation Assets
Alameda Municipal Power	425	NCPA, geothermal power, landfill gas power, wind power, peaking gas turbines, power supply contracts
City of Palo Alto Utilities	953	NCPA, power supply contracts
City of Healdsburg	66	NCPA, power supply contracts
Port of Oakland	50	Power supply contracts, 800 kW solar PV array (SunEdison)
San Francisco PUC	872	Hetchy Hetchy reservoir hydroelectric, 400 MW peak, 200 MW average
Silicon Valley Power	2,770	NCPA, 147 MW combined cycle plant, power supply contracts
Total:	5,136	

These Bay Area POUs are all members of the Northern California Power Agency (NCPA) and purchase some of their electricity supply from the NCPA. NCPA is a non-profit joint powers agency that represents seventeen cities and districts in Northern and Central California. NCPA states, "NCPA was founded in 1968 as an agency through which community-owned utilities could prevent costly market abuses employed by private utilities at that time, and to make investments to create an affordable, reliable and clean future energy supply for the electric ratepayers we serve."[49]

NCPA generation assets consist of two 110 MW geothermal plants at The Geysers in Sonoma County, 252 MW of hydroelectric capacity, and 174 MW of natural gas-fired peaking turbines. NCPA has also established a Green Pool, where member utilities can contract for a mix of renewable resources.[50]

3.5.2 San Francisco Public Utilities Commission (SFPUC)[51]

San Francisco receives electricity from the Hetch Hetchy hydroelectric project to meet the demand of city-owned facilities. This electricity supply is administered by the SFPUC. The city first began generating power in 1921. The Raker Act granted San Francisco rights to federal lands in and adjacent to Yosemite National Park to develop the dam at Hetch Hetchy and associated reservoirs and hydropower generation facilities.

San Francisco operates three powerhouses – Mocassin, Holm and Kirkwood. These powerhouses contain seven turbines capable of producing a total of 401 MW of electricity during the spring run-off when the reservoirs behind the powerhouses are full. During a year with average rainfall, the Hetch Hetchy project is capable of producing 1.7 million MWh of electricity. This is an average output of about 200 MW over the course of the year.

San Francisco also owns approximately 150 miles of high voltage transmission lines that link the Hetch Hetchy power plants with the PG&E transmission grid at Newark. This power supply system is shown in Figure 3-6. The output of the Hetch Hetchy power plants exceeds San Francisco's municipal power demands on an annual basis. However, San Francisco supplements its power sources to meet municipal demand and its contractual obligations during the summer and fall months when power generation is reduced so that water can be stored.

Figure 3-6. San Francisco Hydroelectric Generation Facilities and Transmission Lines[52]

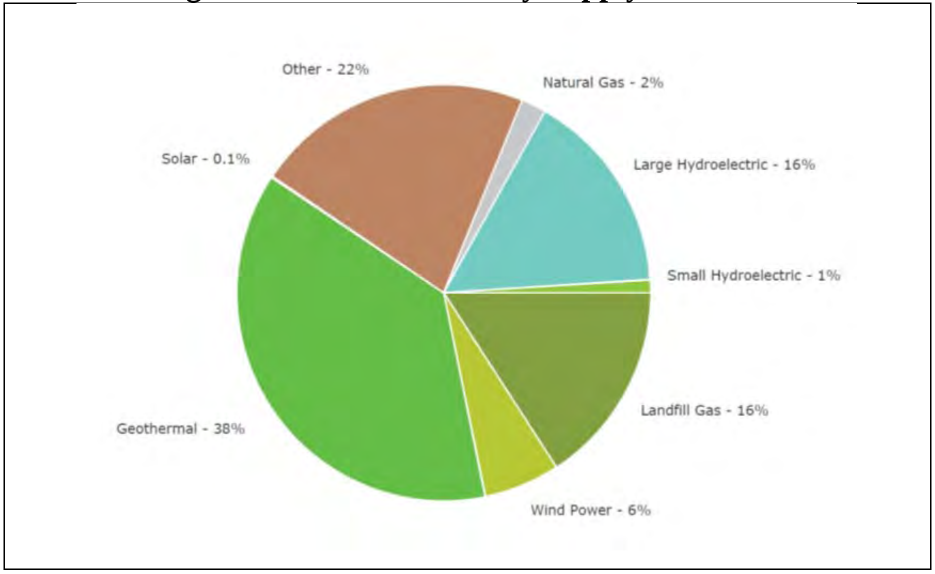
The Raker Act requires that any power that is surplus to the San Francisco's municipal needs be made available at cost to the Modesto and Turlock Irrigation Districts to meet their municipal needs. The Raker Act prohibits the sale of Hetch Hetchy-generated electricity to IOUs. San Francisco cannot sell any surplus power to PG&E or other private entities within its boundaries.

3.5.3 Alameda Municipal Power (AMP)

AMP serves approximately 30,000 residential customers, and 4,000 commercial, industrial, and municipal customers.[53] As shown in Figure 3-7, a high proportion of AMP's electricity supply is generated by renewable energy sources, with geothermal power from The Geysers, landfill gas, and wind power providing more than 60 percent of annual supply.

In addition, 16 percent of the AMP electricity supply is provided by wholesale energy broker Morgan Stanley under a 15-year contract. This contract ends in December 2014. Six percent of AMP's electricity supply is obtained through purchases made by AMP in the wholesale electricity market.[54]

Figure 3-7. AMP Electricity Supply Sources[55]



3.5.4 Silicon Valley Power (SVP)

The City of Santa Clara municipal utility launched its 6 MW CHP No. 1 power plant in 1980 to become a generating utility. In 1983, the 110 MW NCPA geothermal project entered service with Santa Clara as a lead partner. The utility changed its name to Silicon Valley Power in 1998. The utility's 147 MW Donald Von Reasfeld combined cycle plant came online in June 2005. SVP owns, operates and participates in more than 380 MW of generating resources and serves a peak load of approximately 460 MW.[56] SVP serves approximately 52,000 customers of all types.[57]

SVP offers its small commercial, large commercial, and industrial customers the option to purchase renewable energy. The renewable energy is from western state wind and California solar projects. It is available for an additional $0.015/ kWh for small businesses, or in 1,000 kWh blocks for $15 each for large businesses.[58]

3.5.5 City of Palo Alto Utilities (CPAU)

CPAU meets Palo Alto's electricity needs through its electric supply contracts and partnership in the NCPA.[59] The CPAU does not operate generation resources. The CPAU supplies approximately 1,000 GWh per year to about 30,000 customers and has a peak load of 186 MW. Approximately 24 percent of CPAU's electricity supplies are from renewable energy sources.[60]

The CPAU has also operated PaloAltoGreen since 2003. This program allows customers to purchase 100 percent renewable energy at a premium of $0.015/kWh. Twenty-one percent of CPAU's customers participate in the PaloAltoGreen program.[61] The CPAU is launching its multi-year Clean Local Energy Accessible Now (CLEAN) Program, a feed-in tariff program for commercial rooftop PV systems 100 kW and greater in capacity, in April 2012. The 2012 target is 4 MW of commercial rooftop PV 100 kW or greater with a proposed payment of $0.14/kWh.[62]

3.6 Comparison of POU and PG&E Rates

Bay Area POU rates are consistently lower than PG&E rates for comparable service. Table 3-6 compares the commercial tariff of PG&E to the commercial service tariff for: 1) AMP, 2) CPAU Green Small Commercial, 3) CPAU Small Commercial Green, which is the CPAU program for commercial customers electing 100 percent renewable power, 4) SVP commercial, and 5) Santa Clara Green Power, which is the SVP program for customers electing 100 percent renewable power. In all cases the POU tariffs are lower than the comparable PG&E commercial tariff. The conventional POU commercial tariffs are 12 to 23 percent lower than the comparable PG&E tariff. The 100 percent renewable energy commercial tariffs available from the CPAU Green and Santa Clara Green Power programs are 3 to 14 percent lower than the PG&E commercial tariff.

Table 3-6. Comparison of Commercial Rates: PG&E, AMP, CPAU, and SVP

Basic commercial service	Energy charge, average ($/kWh)	Energy charge, summer ($/kWh)	Energy charge, winter ($/kWh)	POU rates compared to PG&E rate (%)
PG&E[63]	0.17230	0.19712	0.14747	base case
AMP[64]	0.14107	NA	NA	-18
CPAU Small Commercial[65]	0.13353	0.14045	0.12661	-23
CPAU Small Commercial Green[66]	0.14853	0.15545	0.14161	-14
SVP[67]	0.15136	NA	NA	-12
Santa Clara Green Power[68]	0.16636	NA	NA	-3

3.7 Community Choice Aggregation in PG&E Territory

CCAs are in many respects similar to public utilities, in that they generate or purchase electricity supplies that are delivered to customers. However, CCAs rely on the IOUs serving their area to provide T&D service to customers within the CCA. In contrast, an IOU provides both electricity supply and T&D service to its bundled customers.[69]

Three entities have pursued CCAs since AB 117 was passed into law in 2002: the San Joaquin Valley Power Authority (SJVPA), Marin County, and San Francisco.

The CPUC authorized its first CCA application under AB 117 on April 30, 2007. The CCA application was submitted by the Kings River Conservation District on behalf of SJVPA. The SJVPA is intended to serve the cities of Clovis, Hanford, Lemoore, Corcoran, Reedley, Sanger, Selma, Parlier, Kingsburg, Dinuba, Kerman, and Kings County. The introduction to the SJVPA implementation plan provides an excellent summary of the expected benefits of forming a CCA. The following paragraphs are excerpts from the implementation plan:

> "The Authority's primary objective in implementing this Program is to enable customers within its service area to take advantage of the opportunities granted by Assembly Bill 117 (AB 117), the *Community Choice Aggregation Law*. The benefits to consumers include the ability to reduce energy costs; stabilize electric rates; increase local electric generation reliability; influence which technologies are utilized to meet their electricity needs (including a potential increased utilization of renewable energy); ensure effective planning of sufficient resources and energy infrastructure to serve the Members' residents and businesses; and improve the local/regional economy.
>
> The Authority's rate setting policies establish a goal of providing rates that are lower than the equivalent generation rates offered by the incumbent distribution utility (PG&E or SCE). The target rates are initially at a five percent discount with the discount potentially increasing once additional Kings River Conservation District-owned resources are brought on-line."

The SJVPA suspended development efforts in June 2009 due to weakness in the credit markets.[70]

PG&E spent more than $46 million in 2010 on an unsuccessful effort to pass Proposition 16, "New Two-Thirds Vote Requirement for Local Public Electricity Providers."[71] Proposition 16 would have required cities and counties to win the approval of two-thirds of their voters before spending public money to start or join a public power agency. The specific focus of Proposition 16 was to stall the development of CCAs in California.[72]

The Marin Energy Authority launched its CCA program, *Marin Clean Energy*, in May 2010.[73] *Marin Clean Energy* is the state's first operational CCA. *Marin Clean Energy* is in the process of expanding its customer base from 14,000 customers to approximately 100,000 customers, as all Marin County residents will have the opportunity to participate in mid-2012.[74] Marin Energy Authority is contracting with Shell to provide electricity to customers.[75] *Marin Clean Energy* offers its customers three options with varying renewable energy content: 25 percent, 50 percent, or 100 percent.

The San Francisco Public Utilities Commission is in the process of launching its CCA program, *CleanEnergySF*, with an initial participation target of 75,000 customers.[76] *CleanEnergySF* will offer a single option, 100 percent green energy.[77] Sonoma County is also considering the formation of a CCA.[78]

Recent changes to CCA legislation allow the CCA to administer public goods funds collected from CCA customers. These funds have historically been controlled by the investor-owned utility. The CCA can now independently determine how these funds will be used to maximize energy efficiency reductions in the CCA jurisdiction.

Two major issues of concern related to the formation of a CCA are: 1) departing load charges, also known as exit fees, levied by PG&E on CCA customers, and 2) the need to post a bond in case the CCA should fail and the customers by default abruptly return to PG&E service.[79] Departing load charges are assigned to customers that leave PG&E service after PG&E has made financial commitments to build or contract for specific new generation and/or transmission projects. For example, if there were 5 million PG&E customers at the point in time when certain generation and transmission projects were approved, and then 500,000 customers shift to a CCA, the cost of the new projects would have to be recovered from the 4.5 million remaining customers until customer growth replaces the CCA customers.

The exit fee for CCA customers is currently projected to be in the range of $0.01 to 0.015/kWh.[80] The projected bond value for the proposed Sonoma County CCA is in the range of $700,000.[81] No bond value has yet been specified by the CPUC for the San Francisco CCA program, *CleanPowerSF*.[82]

Three valuable contributions a CCA can provide to customers relative to service from PG&E are: lower rates, a higher percentage of renewable energy, and more local control of the sources of electricity supply. Another important indirect contribution is the value of competition in shaping the development strategy pursued by PG&E. If CCA becomes a readily accessible option for California cities and counties, PG&E is more likely to mimic the products and benefits that a CCA would provide in order to avoid further erosion of its customer base.

3.8 PG&E History and Current Procurement Practices

PG&E was formed in 1905 by the merger of the San Francisco Gas and Electric Company and the California Gas and Electric Company.[83] A primary objective of the newly formed company was to develop the hydroelectric potential of rivers in the Sierra Nevada.[84] The state granted monopoly status to PG&E as a supplier of electricity in Northern California in the 1930s. The basic architecture of the high voltage transmission system bringing power into the Bay Area was formed by the 1950s.

PG&E built fossil fuel power plants in Pittsburg and Moss Landing in the 1950s and 1960s to serve the Bay Area. In San Francisco, PG&E built smaller plants at Hunters Point in 1958 and Potrero in 1965 to provide generation resources at the end of its transmission lines.

PG&E and SCE made a commitment to develop nuclear power in the late 1960s. Both California utilities faced challenges during construction that caused significant delays and cost escalation. At the beginning of the 1980s, slippage in the construction schedules at Diablo Canyon and San Onofre led to concerns about possible shortages of electricity in California.

The CPUC aggressively promoted non-utility development and ownership of power plants to spur the addition of more capacity. California led the nation in encouraging the development of geothermal, biomass, wind, and solar thermal generating capacity by taking advantage of a 1978 federal law, the Public Utility Regulatory Policy Act (PURPA). About 11 percent of California's electricity came from non-hydro renewable energy sources by the early 1990s. The CPUC also ordered PG&E to institute demand-side management programs. These are programs that provide incentives to customers to curtail electricity consumption during times of peak electricity demand.

PG&E Corporation, PG&E's parent company formed in 1997, is an active developer and operator of energy projects in and around PG&E service territory.[85] PG&E Corporation owns numerous affiliates in addition to PG&E. These include: PG&E Real Estate, LLC; PCG Capital, Inc.; Sequoia Pacific Solar I, LLC; SunRun Pacific Solar LLC; Pacific Energy Capital I, LLC; Pacific Energy Capital II; LLC, Pacific Energy Capital III, LLC; and Pacific Energy Capital IV; Midway Power, LLC; PG&E Strategic Capital, Inc.; and Ruby Pipeline LLC.[86] PG&E Pacific Venture Capital LLC, now Pacific Energy Capital I, LLC, was formed in 2010 and provides capital to solar PV leasing firms SolarCity and SunRun.[87] PG&E invested $60 million in SolarCity in January 2010 and $100 million in SunRun in June 2010.[88,89]

3.8.1 Deregulation and 2000-2001 Energy Crisis

The California legislature unanimously passed legislation in 1996 to end the monopoly power of the IOUs, eliminate government supervision of electric resource planning, and give consumers a choice of electricity suppliers.[90] As allowed in the legislation, PG&E opted to sell-off most of its fossil fuel and geothermal power plants to private companies not regulated by the state.

PG&E transmission lines were placed under the control of the newly created CAISO. PG&E retained responsibility for running the T&D system and procuring power from the wholesale market for customers who did not choose an alternate provider. The rates that PG&E could charge those default customers were still regulated by the CPUC. This deregulated system collapsed in early 2001 under the weight of market manipulation. PG&E filed for bankruptcy in April 2001. The State of California, through long-term electricity supply contracts administered by the DWR, became the power buyer of last resort.

Under deregulation PG&E retained ownership of the Diablo Canyon nuclear plant, the Humboldt power plant, and the Hunters Point power plant. PG&E entered into an agreement with San Francisco in 1998 to close Hunters Point when it was no longer needed for electric reliability in San Francisco. Hunters Point was permanently closed in 2006 with the start-up of the Jefferson-Martin 230 kV transmission line that connects San Francisco to a substation in San Carlos.[91] PG&E sold the Potrero power plant to Mirant in 1999. Potrero was permanently closed in December 2010 with the startup of the 400 MW Trans Bay Cable from Pittsburg to Hunters Point.[92]

A public goods charge was added to customers' electric bills in 1997 to fund the continuation of energy-efficiency and renewable programs in the deregulated era. PG&E has been collecting the public goods charge since 1997 and using the funds to administer PG&E energy efficiency programs under the direction of the CPUC.

3.8.2 PG&E's Procurement Process in the 21st Century

The period after 2001 consists of a hybrid mix of IOU ownership and third party electricity providers. The CPUC returned the long-range strategic planning function to PG&E, SCE, and SDG&E in 2003. Generation and transmission needs identified by the IOUs serve as the basis for new CPUC power plant and transmission line authorizations. The IOUs were also allowed by the CPUC to build or acquire new generation assets. Examples of new power plants built by PG&E include the 590 MW Gateway combined cycle plant in Antioch and the 660 MW Colusa combined cycle plant in Colusa County.

A fundamental tenet in the move toward a deregulated electricity market was the concept that market price signals alone would be sufficient to get new power plants built as they were needed. The CPUC ended this laissez-faire approach following the energy crisis by authorizing the IOUs to pass on all fixed costs associated with new power plant power purchase agreements to ratepayers. In simple terms, the CPUC removed all market risk from the developer and shifted that risk, in the form of guaranteed payment for all fixed costs, to the ratepayer.[93]

PG&E completed its 2004 long-term request for offers process in 2006. This process was intended to result in the construction of 2,250 MW of new peaking and load-following natural gas-fired generation. The identification and status of these proposed generation additions are provided in Table 3-7.[94]

Table 3-7. Description and Status of PG&E Gas-Fired Power Purchase Agreements Approved by CPUC in 2006

Facility	Capacity (MW)	Plant Type	Operational Date	Status
Calpine Hayward (Russell City Energy Center)	601	combined cycle	June 2010	delayed, 2013 projected start date
EIF Firebaugh (Panoche Energy Center)	400	combustion turbine	August 2009	operational
EIF Fresno	196	combustion turbine	September 2009	cancelled
Starwood Firebaugh (Starwood Power-Midway)	120	combustion turbine	May 2009	operational
Tierra Energy Hayward	116	reciprocating engine	May 2009	cancelled
E&L West Coast Colusa	660	combined cycle	May 2010	operational
Wartsila Humboldt (modernization project)	163	reciprocating engine	May 2009	operational

PG&E recommended in its *2006 Long-Term Procurement Plan* application that up to 2,300 MW of new natural gas-fired capacity, beyond the additions listed in Table 3-7, come on-line beginning in 2011. This new capacity is based on PG&E's use of a 16 percent reserve margin for a 1-in-10 temperature peak demand event. This is a more rigorous level, necessitating more capacity, than the CPUC planning requirement. The CPUC requirement is a 15 to 17 percent reserve margin for a 1-in-2 temperature year peak demand event.[95]

The summer of 2006 heat storm was used by PG&E in its *2006 Long-Term Procurement Plan* application as a primary basis for substantial new additions of natural gas-fired capacity. PG&E estimates that the summer of 2006 heat storm was a 1-in-30 to 1-in-40 high temperature event.[96]

The CPUC in December 2007 authorized PG&E to procure 800 to 1,200 MW of additional gas-fired generation by 2015 to maintain a reserve margin of 15 to 17 percent.[97] The CPUC required that PG&E procure dispatchable ramping resources that can be used to adjust for the morning and evening "ramps" created by intermittent types of renewable resources. The CPUC also stated in the decision that preference should be given to procurement that will encourage the retirement of aging plants using once-through cooling, by providing qualitative preference for bids involving the repowering of the once-through cooled plants or bids for new facilities at locations in or near the load pockets where the once-through cooled plants are located.

The actual reserve margin in PG&E territory in 2009 was 44 percent.[98] The actual 2009 peak was somewhat below the peak forecast for a 1-in-2 temperature event year.[99] The actual 2010 reserve margin at the peak hour was 38.3 percent using the CAISO estimate of available supply in PG&E territory in August 2010.[100] The actual 2010 peak load of 21,180 MW was slightly higher than the 1-in-2 peak demand of 21,154 MW forecast by CAISO.[101] The 2011 PG&E peak load occurred between 4 pm and 5 pm on June 21, 2011 and was 19,791 MW.[102] The actual 2011 peak load was lower than the CAISO forecast 1-in-2 peak load of 21,360 MW.[103] The actual reserve margin in 2011 was 44 percent.[104]

Despite the exceptionally high actual 2009 and 2010 reserve margins, the CPUC approved PG&E's application for a power purchase agreement for the simple cycle 200 MW Mariposa Energy Center in September 2009,[105] the 760 MW simple cycle Marsh Landing project in July 2010, and the 624 MW Oakley combined cycle project in December 2010.[106,107]

The CPUC has also authorized a 500 MW distributed PV project in PG&E territory. The project includes a 250 MW IOU-owned component and a 250 MW competitively bid third party component. The PG&E 500 MW distributed PV project was approved by the CPUC in April 2010. The CPUC observed with its approval of the PG&E 500 PV project that:[108]

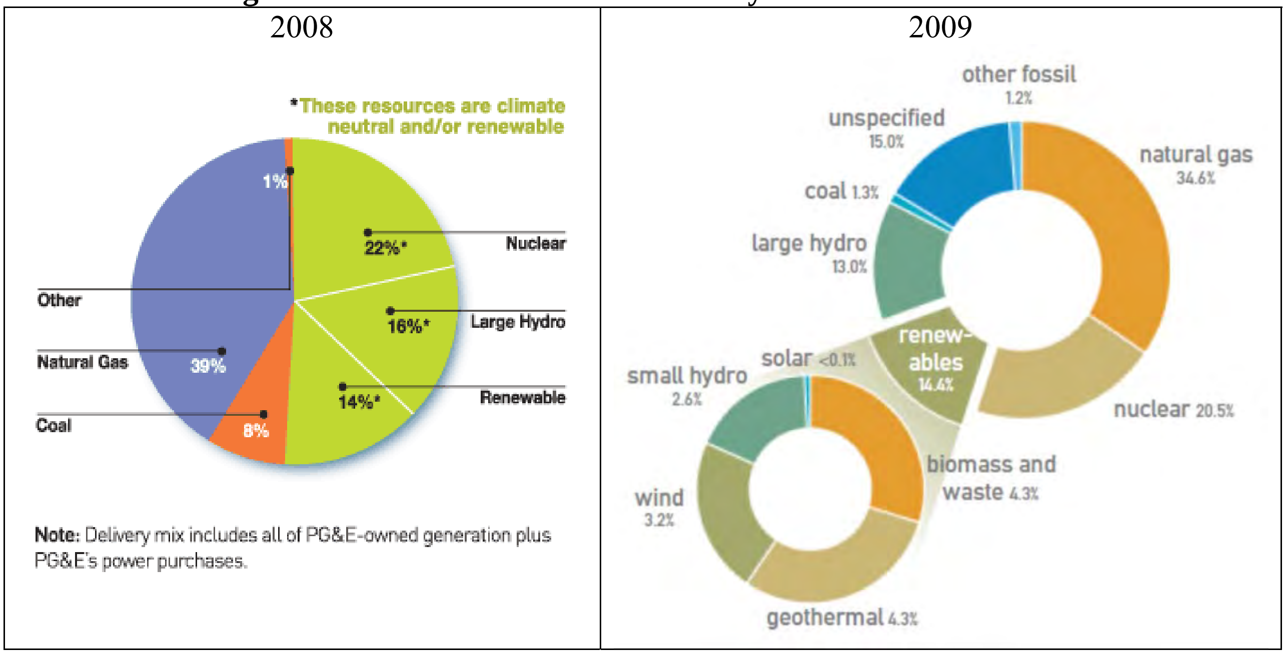
> "This solar development program has many benefits and can help the state meet its aggressive renewable power goals," said CPUC President Michael R. Peevey. "Smaller scale projects can avoid many of the pitfalls that have plagued larger renewable projects in California, including permitting and transmission challenges. Because of this, programs targeting these resources can serve as a valuable complement to the existing Renewables Portfolio Standard program."

The end result of approving too many new natural gas-fired generation projects is captured in the CPUC's *2010 Long Term Procurement Proceeding*.[109] Assuming only modest gains in energy efficiency over the next decade, and relatively little addition of new CHP, the projected reserve margins in PG&E service territory will be over 60 percent for every year between 2011 and 2020 in six of the seven PG&E scenarios evaluated by the CPUC. In one scenario, the 33 percent renewable energy trajectory low-load scenario, the reserve margin reaches 100 percent in 2016.[110]

3.8.3 PG&E's Renewable Procurement Efforts

PG&E delivers electricity that is: 1) generated at power plants owned by the company, and 2) purchased from third parties. The sources of electricity supplied by PG&E in 2008 and 2009 are shown in Figure 3-8.

Figure 3-8. PG&E Sources of Electricity in 2008 and 2009[111,112]



PG&E owns the 2,200 MW Diablo Canyon nuclear power plant, the 590 MW Gateway natural gas-fired combined cycle plant in Antioch, the 660 MW Colusa natural gas combined cycle plant in Colusa County, and the 163 MW Humboldt natural gas-fired engine power plant in Eureka. PG&E also owns and operates the 1,212 MW Helms Power Plant pumped storage project in Fresno County. In addition, the company owns 2,853 MW of baseload hydroelectric capacity distributed among 67 separate plants.[113]

PG&E has contracts with about 260 "qualifying facilities" totaling more than 4,100 MW of capacity.[114] These qualifying facilities are the outcome of the passage of PURPA in 1978. PURPA sought to reduce the country's dependence on oil through the development of new resources for electric generation, including renewable resources such as solar, wind, biomass, geothermal, and small hydro, and the more efficient use of oil and gas in CHP projects.

PURPA's key reforms included a requirement that the utilities must purchase the power output of qualifying CHP and other small power producers. Collectively these sources are known as qualifying facilities.[115] Most of California's qualifying facilities were developed and built between 1982 and 1990, under 20- to 30-year contracts which provided for the sale of excess electricity to the utility.

PG&E receives electricity supply under long-term power contracts signed in the wake of the 2000-2001 energy crisis. These contracts are administered by the DWR. Most of the DWR contracts expire in the 2010 to 2012 timeframe.[116] The amount of electricity supplied to PG&E

under the DWR contracts is substantial. As shown in Table 3-9, four of the top seven PG&E electricity sources in 2008 were DWR contracts totaling nearly 20,000 GWh. These four DWR contracts represented nearly 25 percent of all electricity delivered by PG&E in 2008.[117]

PG&E also imports power from sources outside the region, identified in Figure 3-11 in the 2009 power mix graphic under the header "unspecified." This unspecified allocation includes coal power from neighboring western states. As shown in Figure 3-8, coal power accounted for 8 percent of PG&E's electric power sales in 2008.

In 2009, 14.4 percent of the electric energy sold by PG&E, around 11,500 GWh, was generated by renewable energy sources.[118] The renewable energy sources contributing to the 14.4 percent total are identified in Figure 3-11. PG&E's renewable energy percentage increased to 17.7 percent in 2010.[119] Much of this renewable energy is generated in PG&E service territory. Major renewable development areas include The Geysers in Sonoma County, wind in Solano County, and wind in Altamont Pass in Contra Costa and Alameda counties.

SB 2 (1X) was signed into law by Governor Brown in April 2011 and requires at least 20 percent of the total electricity sold to retail customers in California be from renewable energy sources by December 31, 2013, and reach 33 percent by December 31, 2020.[120]

The top fifty in-state sources supplying electricity to PG&E in 2008 are shown in Table 3-8.

Table 3-8. Top Fifty In-State Generation Sources Supplying Electricity to PG&E in 2008[121]

Plant	Fuel Type	GWh supplied
PG&E: DIABLO CANYON – Unit 1	nuclear	9,895
PG&E: DIABLO CANYON – Unit 2	nuclear	8,496
DWR: CALPINE1 (PR1)	natural gas	7,610
DWR: CALPINE2 (PR1)	natural gas	7,610
DWR: CORAL	natural gas	3,217
PCWA: MIDDLE FORK	large hydroelectric	1,398
DWR: DISPATCHABLE CONTRACTS	natural gas	1,110
YCWA: COLGATE	large hydroelectric	902
TOLLING AGREEMENT: MOSS LANDING 6 & 7	natural gas	814
CALPINE KING CITY COGEN	natural gas	751
PG&E: CARIBOU 2 PH	large hydroelectric	745
YCWA: COLGATE	large hydroelectric	724
PG&E: HAAS PH	large hydroelectric	708
PG&E: BELDEN PH	large hydroelectric	679
PG&E: KERCKHOFF #2 PH	large hydroelectric	640
GEYSERS POWER COMPANY, LLC	geothermal	581
CROCKETT COGEN	natural gas	568
PG&E: ELECTRA PH	large hydroelectric	562

Table 3-8. Top Fifty In-State Generation Sources Supplying Electricity to PG&E in 2008 (cont.)

Plant	Fuel Type	GWh supplied
PG&E: PIT 5 PH	large hydroelectric	507
MID: EXCHEQUER	large hydroelectric	504
PG&E: JAMES B. BLACK PH	large hydroelectric	499
PG&E: PIT 5 PH	large hydroelectric	475
PG&E: STANISLAUS PH	large hydroelectric	474
CALPINE GEYSERS #13	geothermal	472
PG&E: CRESTA PH	large hydroelectric	440
PG&E: PIT 4 PH	large hydroelectric	419
PG&E: PIT 3 PH	large hydroelectric	416
PG&E: POE PH	large hydroelectric	406
PG&E: POE PH	large hydroelectric	403
STOCKTON COGEN	coal	340
MT. POSO COGENERATION	coal	383
MIRANT WRAP AGREEMENT: PITTSBURG 5 & 6	natural gas	377
TRI-DAM DONNELLS	large hydroelectric	372
WHEELABRATOR SHASTA	biomass & waste	361
PG&E: ROCK CREEK PH	large hydroelectric	355
BEAR MOUNTAIN LIMITED	natural gas	354
OWID: WOODLEAF	large hydroelectric	348
PG&E: ROCK CREEK PH	large hydroelectric	347
CHALK CLIFF LIMITED	natural gas	346
McKITTRICK LIMITED	natural gas	342
LIVE OAK LIMITED	natural gas	341
PG&E: BALCH 2 PH	large hydroelectric	338
PG&E: DRUM 2 PH	large hydroelectric	338
BADGER CREEK LIMITED	natural gas	332
PG&E: PIT 7 PH	large hydroelectric	330
HIGH SIERRA LIMITED	natural gas	319
KERN FRONT LIMITED	natural gas	319
PG&E: TIGER CREEK PH	large hydroelectric	319
DUKE TOLLING AGREEMENT: MORRO BAY 3 & 4	natural gas	318
COALINGA COGENERATION COMPANY	natural gas	314

4. California Independent System Operator

The California Independent System Operator (CAISO) was created in 1996 by state law as a private, non-profit corporation to run the transmission grid.[122] CAISO also administers a centralized electricity market in California with participation by the IOUs and less closely regulated market participants like independent power producers. CAISO operates in interstate commerce and for this reason is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). The CAISO control area encompasses the transmission assets of PG&E, Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E), and some of the California publicly-owned utilities (POUs). A primary purpose of CAISO is to assure adequate electricity supply to assure grid reliability within its control area.

The transmission systems of numerous public utilities in California operate independent of CAISO control. These transmission systems include those of the Los Angeles Department of Water and Power (LADWP), Sacramento Municipal Utility District (SMUD), Imperial Irrigation District, Turlock Irrigation District, and Merced Irrigation District. In addition, some of the POU transmission lines that are within the CAISO control area, such as the SFPUC transmission lines connecting Hetchy Hetchy hydroelectric power to San Francisco, are operated outside of the CAISO's open access market structure. These transmission lines are operated under transmission access provisions that recognize pre-existing transmission contracts.

A central role of CAISO is to ensure the reliability of electricity supply for loads within the CAISO control area. The CAISO mission statement summarizes the purpose of the organization:[123]

> "For the benefit of our customers, we operate the grid reliably and efficiently, provide fair and open transmission access, promote environmental stewardship, facilitate effective markets, and promote infrastructure development."

CAISO was intended to serve as a neutral authority that would balance the predisposition of IOUs to build new transmission and natural gas-fired power plants by pooling generation resources to achieve cost savings for consumers. Since 2001, CAISO has increasingly become a champion for the generation and transmission infrastructure expansion plans of the IOUs in its control area.

4.1 Transmission and Renewable Energy Development

California's transition to higher levels of renewable energy is now the primary rationale put forth by CAISO for major IOU transmission expansion projects. Yet the economic and technical support for this rationale is weak, as explained in a July 2010 analysis in Natural Gas & Electricity Journal of the transmission expansion underway in California:[124]

> "In the West, there is a widespread perception of a transmission shortage. This perception has grown out of the consistently repeated claims of the utilities, balancing authority operators

> such as the CAISO, and state agencies such as the CEC, that the lack of transmission is threatening the success of the region's renewable energy and clean air programs. A particularly troubling outcome of this perception is that many parties, including renewable generation developers, have come to believe that the slow pace of connecting new generation to the grid is the result of a widespread transmission shortage. . . In fact, the evidence points strongly in the opposite direction. Transmission investment has far outpaced the rate at which energy demand has been growing, and congestion-related impacts in most areas of the interconnected grid have been relatively minor, certainly not at levels that would justify massive increases in new transmission investment.
>
> Considering that renewable generation additions will displace fossil-fired generation throughout the Western Electricity Coordinating Council, thereby reducing the amount of fossil-fired generation imported into the state of California to serve loads, more transmission capacity will be available on the major import paths into California. This is significant for California because much of the renewable resource development potential exists along these major import paths. If the major import paths can be used to deliver renewable energy to California's load centers, then the only significant transmission additions that are needed are those that will collect and connect the new renewable resources to the existing grid."

The conclusion of this analysis is that, as long as IOU profits are tied directly to the amount of transmission rate base they can accumulate, the motivation to find creative ways to avoid economic comparisons with alternatives will continue.

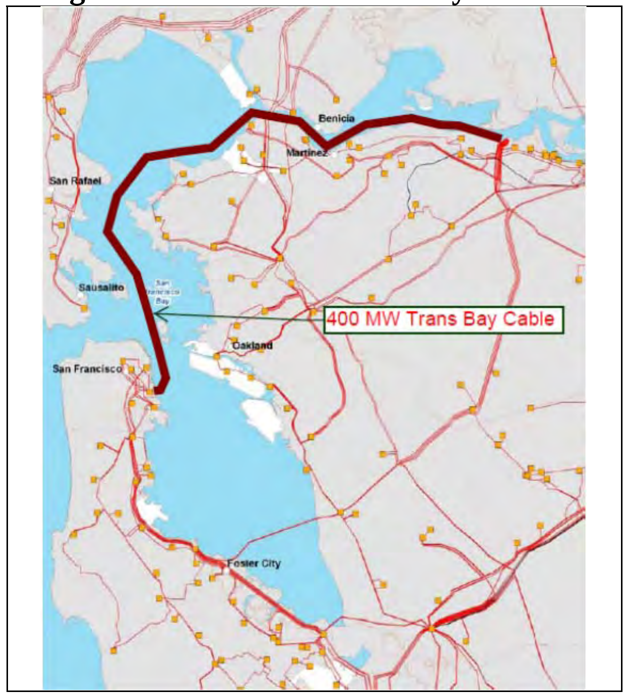
As shown in Table 4-1, the increase in the California IOU transmission rate base over the 1999–2009 period was over $5 billion, an 84 percent increase. The increase in electricity demand was about 9 percent over the same period.

Table 4-1. California IOU Transmission Investment Compared to Electricity Demand Growth, 1999 – 2009[125]

Year	Transmission rate base ($ million)	Transmission rate base growth rate	Net electricity supplied by IOUs	Growth in electricity supplied by IOUs
1999	6,176	1.00	214,826	1.00
2000	6,420	1.04	227,310	1.06
2001	6,633	1.07	211,812	0.99
2002	6,884	1.11	214,230	1.00
2003	7,224	1.17	218,316	1.02
2004	7,861	1.27	226,171	1.05
2005	8,459	1.37	227,787	1.06
2006	9,078	1.47	234,834	1.09
2007	10,024	1.62	239,540	1.12
2008	10,773	1.74	243,842	1.14
2009	11,371	1.84	235,093	1.09

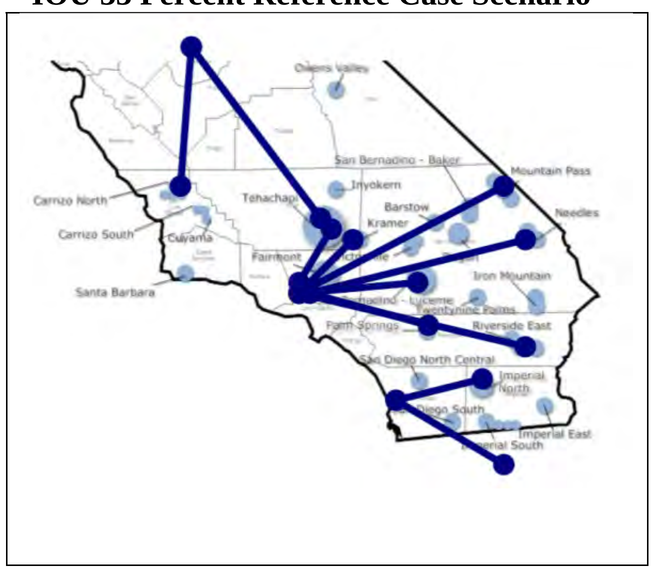
The most recent major transmission project approved by CAISO in the Bay Area is the 400 MW Trans Bay Cable, shown in Figure 4-1. This $500 million, 53-mile underwater direct current transmission line began operation in November 2010.[126] The line is a public-private partnership between the City of Pittsburg and SteelRiver Infrastructure Partners.[127] It is being financed by a cost-based infrastructure recovery charge approved by CAISO in 2005. This charge is paid by all California IOU customers. CAISO has operational control over the Trans Bay Cable. The line connects a cluster of natural gas-fired power plants in the Pittsburg area, and wind generation across the Sacramento River in the Montezuma Hills area of Solano County, directly to San Francisco. The Potrero Power Plant in San Francisco was permanently shut down following start-up of the Trans Bay Cable.[128]

Figure 4-1. 400 MW Trans Bay Cable[129]



The rapid expansion in transmission investment shown in Table 4-1 will grow larger in the next ten years if current IOU transmission expansion plans are realized. These expansion plans are based on the presumption that nearly all new renewable generation will be built at utility scale in remote areas. Proposed lines are shown in Figure 4-2. The cost of proposed California transmission lines to be added by the year 2020 is estimated at over $15 billion.[130] Compared to 1999, the California IOU transmission rate base could increase by over 300 percent if the proposed lines are built. In contrast, the projected increase in electricity demand between 1999 and 2020 is about 25 percent.

Figure 4-2. New Transmission Additions for IOU 33 Percent Reference Case Scenario[131]



4.2 Renewables as Rationale for New Gas Turbines

A similar pattern is occurring with CAISO advocacy for a new generation of peaking gas turbine resources to address the retirement of once-through cooled steam boiler plants, like the Pittsburg and Contra Costa steam boiler plants in Contra Costa County, and the perceived variability of solar and wind resources. These relatively inefficient steam boilers now serve primarily as summer peaking capacity, just as the relatively inefficient simple cycle gas turbines proposed at Marsh Landing and Mariposa Energy Center would primarily serve as summer peaking capacity.

A number of incorrect assumptions frame the debate regarding the need for additional gas turbine capacity. Each of these incorrect assumptions is addressed in the following paragraphs.

Incorrect assumption No. 1 – current levels of reserve capacity are insufficient to cover retirements of once-through cooled steam boiler units. CAISO requires that the IOUs maintain a minimum level of local generation in urban load pockets, including the Bay Area, greater Los Angeles, and San Diego, to assure grid stability under all foreseeable load conditions. This requirement is known as the Local Capacity Requirement, or LCR. CAISO established a 2007 LCR of 4,771 MW for the Bay Area.[132] This LCR was established following the highest one-hour peak load ever recorded in PG&E service territory, 22,650 MW, recorded in July 2006.[133] The 2010 one-hour peak load in PG&E service territory was 21,180 MW, about 1,500 MW lower than the 2006 peak.[134] PG&E forecast a 2011 LCR of 4,025 MW for the Bay Area, nearly 750 MW below the 2007 LCR.[135] The 2011 peak load in PG&E service territory was only 19,791 MW.[136]

The CEC forecasts a peak demand growth rate of 1.3 percent over the 2010 – 2020 period. Using 2010 as baseline year and assuming the projected 1.3 percent peak demand growth rate, PG&E would not reach or exceed the 2006 one-hour peak until the summer of 2016.[137] In reality, peak load declined over 6 percent between 2010 and 2011, from 21,180 MW to 19,791 MW. Actual peak load declined over 12 percent from 2006 to 2011, from 22,650 MW to 19,791 MW.

PG&E identified the need, in late 2006, for Unit 7 at the Contra Costa power plant, a once-through cooled 340 MW steam boiler unit, to remain online until PG&E's 590 MW Gateway combined cycle plant, also known as Contra Costa Unit 8, came online.[138] The Gateway plant came online in 2009.[139] PG&E stated in its strategic plan that the Gateway plant would eliminate the need for the two steam boiler units at the Contra Costa plant to meet local reliability requirements.

CAISO minimizes the significance of the high levels of electricity supply reserves currently available to PG&E and other California IOUs. The actual PG&E reserve margin in 2011 was over 44 percent.[140] This means that PG&E had almost 9,000 MW of actual reserves in the summer of 2011, and nearly 6,000 MW more reserve capacity beyond what it is required to assure grid reliability under expected peak demand conditions. These extra reserves are operational and already available to provide back-up as California transitions to higher levels of solar and wind power.

Incorrect assumption No. 2 – once-through cooled steam boiler units must be retired and cannot be upgraded with low-cost cooling towers. PG&E identified only two other once-through cooled steam boiler units in its service territory, Pittsburg 5 and 6 at 325 MW each, as necessary for LCR over the long term in its 2006 strategic plan.[141] A study commissioned by the California Ocean Protection Council determined in 2008 that the cost to convert Pittsburg 5 and 6 to wet cooling towers to eliminate the marine impacts of once- through cooling would be about $125 million.[142]

Pittsburg 5 and 6 are more efficient than the gas turbines that will replace them. Heat rate is a measure of the thermal efficiency of a fossil-fueled power plant. The higher the heat rate, the less thermally efficient the power plant. Pittsburg 5 and 6 are 50 year-old steam boilers with an average heat rate of 9,811 Btu/kWh at full load.[143] The simple cycle gas turbines to be used at proposed 760 MW Marsh Landing will have heat rates of 11,124 Btu/kWh.[144]

The grid reliability study commissioned by the State Water Resources Control Board (SWRCB) in 2008 determined that, due to extensive recent reinforcement of the transmission grid and the addition of thousands of MW of new natural gas-fired resources, all natural gas-fired once-through cooled boiler plants in California could be permanently retired by 2015 with as little as $135 million in additional expense to California ratepayers.[145] CAISO was unaware of this grid reliability analysis when it was summarized at a CEC-sponsored once-through cooling workshop held a year after its publication. Yet the CAISO representative, acknowledging he had not read the report, dismissed it on-the-spot as uninformed and not credible while testifying at the workshop.[146]

At the workshop, owners of much of California's fleet of once-through cooled steam units stated that the steam units could be upgraded to cooling towers to eliminate once-through cooling at a retrofit cost ranging from $115 to 125/kW.[147,148] This is about one-tenth the cost of new natural gas-fired peaking gas turbine capacity.[149] The presumed mass retirement of the steam units is a primary rationale offered by CAISO to justify thousands of MW of new peaking turbine capacity in PG&E territory and statewide.

Incorrect assumption No. 3 – solar and wind output is unpredictable and therefore a parallel system of fast start back-up natural gas-fired turbines must be available at all times. Solar and wind variability is another justification offered for building thousands of MW of new gas turbine capacity. In reality, solar resources are very reliable during peak summertime demand periods in California. Peak events are driven by air conditioning loads which are driven by solar intensity. Peak demand occurs during clear sky conditions in California's major load centers. An analysis of hour-by-hour solar intensity at the Oakland and San Jose Airports during the peak 100 hours in the PG&E service territory in 2007, which demonstrates the solar resource is fully available during peak hours, is provided in Chapter 7.

The wind resource in California and the Bay Area is also reasonably predictable. Production is typically diurnal in nature, with maximum production in evening, night, and morning, and a lull at mid-day. A 24-hour trace of the summertime wind output in Solano County showing this pattern is provided in Chapter 7.

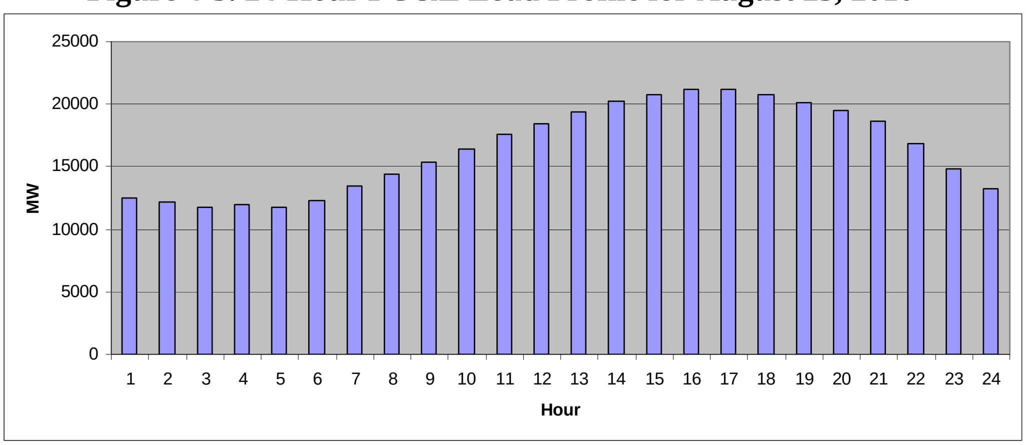
Both the solar and wind output can be predicted with a reasonable degree of accuracy one hour ahead and one day ahead. This is how utilities and CAISO schedule generation now. As higher and higher levels of solar and wind enter the system it may be necessary to schedule more frequently than one hour ahead.[150] However, this is a generator dispatch management issue. It is not a sufficient justification for building a new generation of peaking gas turbines.

The potential for rapid swings in wind and solar output is also put forth as a justification for building a new generation of fast start gas turbines. This is not a significant issue for distributed PV. There are already thousands of widely distributed PV systems in the Bay Area. The output of thousands of widely distributed PV systems is, collectively, relatively smooth on partly cloudy days. The reason for this is that at any given moment the proportion of PV systems exposed to direct sunlight is relatively constant.

Rapid changes in output may occur periodically from the Solano County and Altamont Pass wind production areas under strong and gusty wind conditions. However, the current grid must already accommodate these rapid changes in load, especially in summer. The highest 2010 one-hour load in PG&E territory was recorded on August 25, 2010. Figure 3-10 is the 24-hour load profile for PG&E service territory on August 25, 2010. As shown in Figure 4-3, the load increased at an average of approximately 1,000 MW per hour from 8 am to 2 pm, and decreased at over 2,000 MW per hour from 9 pm to 10 pm. The combined capacity of the Solano County and Altamont Pass wind production areas is about 1,200 MW. The PG&E system already routinely adds about 1,200 MW of load in an hour, and routinely drops this amount of load in 30 minutes.

It is reasonable to assume that wind conditions causing the combined 1,200 MW capacity of the Solano County and Altamont Pass wind production areas to go from maximum output to zero output in a matter of a few minutes would be infrequent events. PG&E has reported no power failures, brownouts, or blackouts resulting from rapid swings in wind power output in Solano County or Altamont Pass. At the current rate of wind production, output variability is within the tolerance limits of the existing PG&E supply mix.

Figure 4-3. 24-Hour PG&E Load Profile for August 25, 2010[151]



There are approximately 300 MW of new wind projects planned for Solano County that have a high probability of being built.[152] No new capacity additions are currently planned for Altamont Pass. It is not credible that the addition of 300 MW of wind power in the Montezuma Hills area of Solano County, a few miles from nearly 4,100 MW of natural gas-fired generation in eastern Contra Costa County, could affect grid reliability in the Bay Area or necessitate the addition of more gas-fired generation in the Bay Area.[153]

Methods available to prevent wind output variability from becoming an operational challenge include: 1) limiting the amount of new wind capacity added to below a threshold level where grid reliability may be affected, 2) disconnecting wind farms from the grid when infrequent gusty windy conditions have the potential to negatively impact grid reliability, and 3) adding energy storage to wind farms to smooth output and prevent gusty wind conditions from compromising grid reliability.

The National Renewable Energy Laboratory (NREL) released the *Western Wind and Solar Integration Study* in May 2010. This study examines the challenges of integrating sufficient wind and solar energy capacity into the grid to produce 35 percent renewable energy by 2017. The study found that the 35 percent target is technically feasible and does not necessitate extensive additional infrastructure, but does require key changes to current operational practice.[154]

NREL determined that utilities will have to substantially increase their coordination of operations over wider geographic areas and schedule their generation on a more frequent basis to accomplish the 35 percent by 2017 objective. Currently generators provide a schedule for a specific amount of power they will provide in the next hour. More frequent scheduling would allow generators to adjust that amount of power based on changes in system conditions such as increases or decreases in wind or solar generation.

Three key findings of the NREL study are: 1) existing transmission capacity can be more fully utilized to reduce the amount of new transmission that needs to be built, 2) to facilitate the integration of wind and solar energy, coordinating the operations of utilities can provide substantial savings by reducing the need for additional back-up generation, such as natural gas-fired plants, and 3) use of wind and solar forecasts in utility operations to predict when and where it will be windy and sunny is essential for cost-effectively integrating these renewable energy sources.

4.3 Conclusions and Recommendations

- Transmission investment has far outpaced the rate at which California electricity demand has been growing.

- Congestion-related impacts in most areas of the grid have been relatively minor and insufficient to support a major transmission expansion.

- Current transmission expansion plans supported by CAISO are based on the presumption that nearly all new renewable generation in California will be built at utility scale in remote areas.

- PG&E maintains a high reserve margin. PG&E had nearly 9,000 MW of reserve capacity at the peak hour in 2011, a reserve margin of 44 percent. This is much higher the 15 to 17 percent reserve margin required by the CPUC.

- PG&E loads already change at a rapid rate in summer. On peak summer days PG&E demand increases by more than 1,000 MW per hour, nearly 200 MW every ten minutes, and decreases by more than 2,000 MW per hour, greater than 300 MW every 10 minutes.

  The Pittsburg and Contra Costa steam boiler units currently used as peaking units and have heat rates comparable to new peaking gas turbines. These steam boiler units can be retrofit to cooling towers, to avoid the marine impact of once-through cooling, for one-tenth the cost of new peaking gas turbines.

- The Governor's Office should convene an independent panel to weigh available evidence regarding the need to replace once-through cooled steam boiler capacity for grid reliability purposes. Available studies by CAISO and SWRCB reach such different conclusions that a technical consensus must be reached at a strategic level before committing to build natural gas-fired replacement plants.

5. PG&E Procurement and GHG Implications

5.1 Compliance with Energy Action Plan Loading Order

PG&E's *2010 Long-Term Procurement Plan* and *2006 Long-Term Procurement Plan* are designed, according to PG&E, to implement the state's *Energy Action Plan*.[155,156] PG&E indicates it is pursuing energy efficiency as a preferred resource in its procurement strategy consistent with the *Energy Action Plan*, and that the company is fully committed to pursuing all cost-effective energy efficient opportunities.[157] However, actual performance has not kept pace with these commitments.

5.1.1 Energy Efficiency

The CPUC issued a report in April 2010 that found that, for the 2006 to 2008 period, PG&E performed poorly in all energy efficiency categories.[158] The CPUC established a system of energy efficiency bonuses and penalties in 2007.[159] PG&E earns maximum profit by exceeding 100 percent of established energy efficiency targets, a standard profit for exceeding 85 percent, no profit in the 65 to 85 percent range, and would be penalized for achieving less than 65 percent.[160] The utility fell into the penalty zone for peak demand savings of 60 percent and natural gas savings of 63 percent, and into the deadband for energy savings of 71 percent.[161]

Residential and small commercial central air conditioning units are the primary contributor to summertime peak loads. The *Energy Efficiency Strategic Plan* targets a 50 percent improvement in efficiency of heating, ventilating, and air conditioning systems by 2020, and a 75 percent improvement by 2030.[162] PG&E offers no rebates for central air conditioner upgrades.[163]

5.1.2 Distributed PV

PG&E included four distributed PV scenarios in its *2006 Long-Term Procurement Plan*.[164] The minimum distributed PV installation rate among these four scenarios is a constant 28 MW per year. The maximum distributed PV installation rate evaluated would be 40 MW per year in 2011, increasing to approximately 300 MW per year in 2016.

The renewable auction mechanism (RAM) PV program was approved by the CPUC on December 16, 2010.[165] Under the RAM format, project developers submit bids in response to periodic IOU solicitations. The lowest bids are selected, even if the lowest bids are above the market referent price. PG&E is protesting the approval of this program. The January 6, 2011 PG&E rehearing request states:[166]

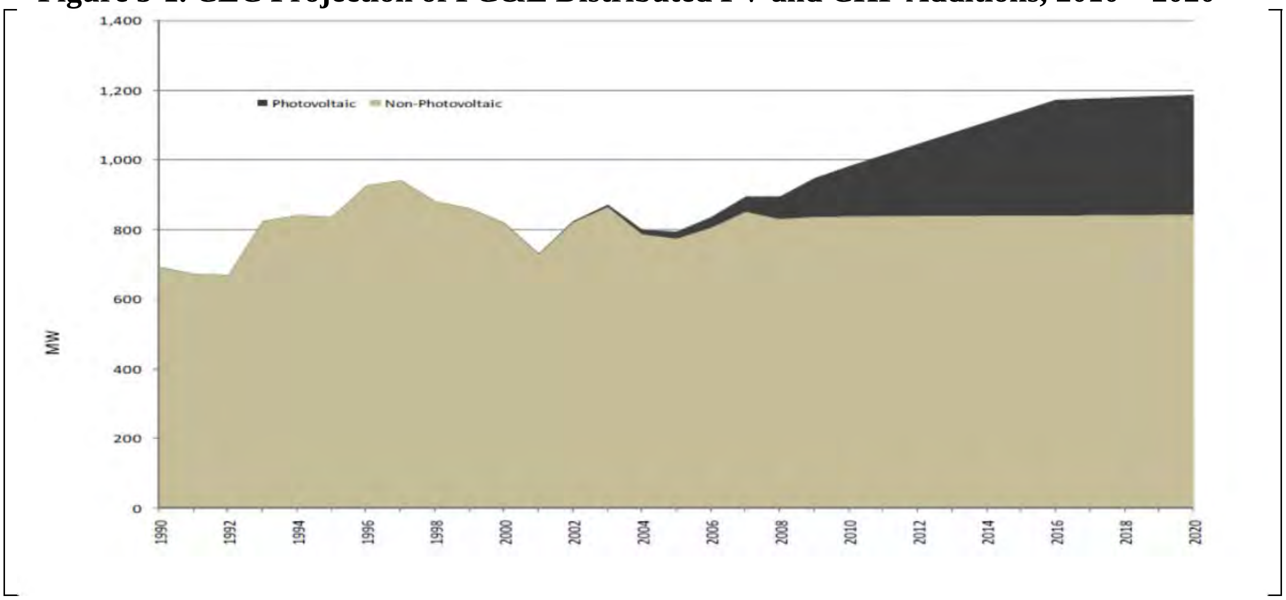
> "PG&E seeks rehearing of the Decision because it violates state law in three ways. First, PG&E's RAM procurement obligation is not limited to procuring only those resources whose prices are at or below the Commission-determined market price referent (MPR), which violates the RPS statute's cost limitation provisions. Second, the Decision does not permit

the investor-owned utilities (IOUs) to suspend their RAM programs if they achieve the 20 percent RPS target, which violates the RPS statute's clear directive that the IOUs cannot be required to procure greater than 20 percent renewables. Third, the Decision applies the RAM program to only the IOUs."

PG&E is clear with this statement that it perceives it will be violating RPS statutory provisions by paying more than the market reference price to procure distributed PV from third party suppliers.

Figure 5-1 is the CEC projection of distributed PV and CHP additions to PG&E territory developed by the CEC for the 2010 – 2020 California electricity demand forecast. There is no net increase in CHP over time, and distributed PV additions end in 2016 with the completion of the *California Solar Initiative*.

Figure 5-1. CEC Projection of PG&E Distributed PV and CHP Additions, 2010 – 2020[167]



5.1.3 CHP

PG&E acknowledges in its *2006 Long-Term Procurement Plan* that there appears to be continuing regulatory and customer interest in expanding reliance on CHP to meet future energy demand in California. The *Energy Action Plan* loading order specifically refers to cost-effective CHP as preferable to traditional sources of electricity generation.

However, PG&E notes that it has seen no indication that customers are more inclined recently to install CHP than they have been in prior years.[168] Consequently PG&E assumes customers will continue historic behavior. This translates into an annual rate of new CHP in PG&E territory of 28 MW per year.[169] At this rate of CHP additions, 280 MW of new CHP would be added over ten years in PG&E territory.

The CPUC issued a proposed settlement agreement in December 2010 for rates to be paid by the IOUs to existing and future CHP plants selling electricity to the IOUs.[170] The settlement agreement recognizes the state's AB 32 implementation target of adding 4,000 MW of new CHP by 2020.[171] PG&E would need to add approximately 1,200 MW of CHP over ten years to meet its portion of the 4,000 MW target.[172]

The CHP settlement agreement includes a bidding process similar to the process in the CPUC's 1,000 MW RAM PV program.[173] CHP developers bid into an IOU request for offers solicitation at a price sufficient to finance and develop their facilities, and the IOUs pick which projects move forward based on selection process similar to the least cost, best fit framework used with RPS bids.[174] The agreement explicitly states that an IOU may use what it deems to be excessive bid prices as justification for failing to meet the MW and GHG reduction targets for CHP in the *AB 32 Scoping Plan*.[175]

PG&E joined with SCE and SDG&E to challenge CHP tariffs that would provide CHP operators with rates that are at or above the 2009 market referent price of approximately $0.10/kWh.[176,177] The IOUs state that CHP electricity is less valuable than the output of a combined cycle natural gas-fired plant, which is the basis for the market referent price, and therefore should be paid less than this reference price. As shown in Chapter 14, a price of at least $0.12/kWh is necessary to assure that CHP projects receive sufficient income from electricity sales to make the project(s) economically viable.

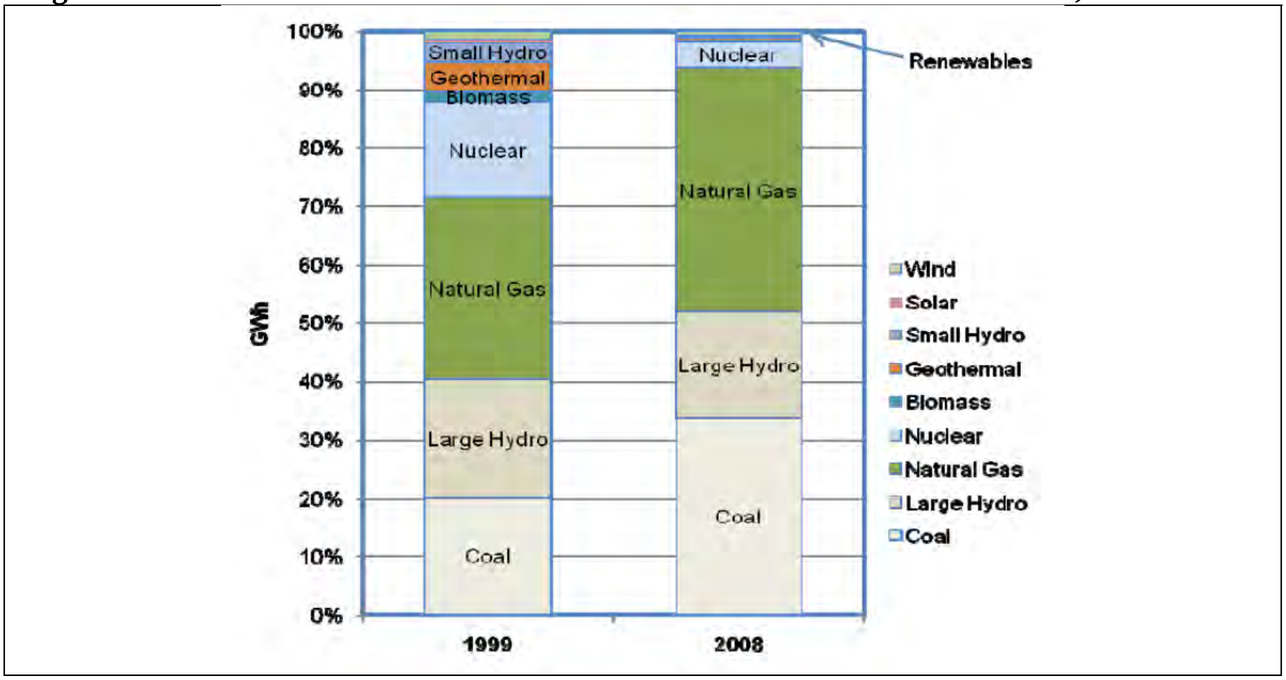
5.1.4 Fossil Generation

Fifty-two percent of the electricity sold by PG&E in 2009 came from fossil fuel sources, as shown in Figure 3-11. As a result of AB 162 and beginning in the 2009 reporting year, California IOUs are no longer required to report the fossil fuel content of wholesale market power purchases.[178] The percentage of coal and natural gas in these wholesale market power purchases has increased over time, as shown in Figure 5-2. The IOUs now state "unspecified" for this category.[179] However, in 2008 PG&E reported that 8 percent of total electricity sales came from coal-fired sources.

Coal-fired cogeneration plants in California under long-term contract to PG&E account for 1.3 percent of sales in 2009. One of these coal plants, Mt. Poso Cogen, completed a conversion from coal to 100 percent biomass in February 2012.[180] A second plant that burns petroleum coke and tire-derived fuel, Stockton Cogeneration, has converted to 20-to-25 percent biomass with plans to increase the biomass content up to 50 percent.[181]

It is important to note that regulation of power imports is included in the scope of the cap-and-trade resolution. The resolution states that CARB staff is to develop requirements to prevent utilities from shifting GHG emissions to imported power to comply with cap and trade requirements.[182] However, AB 162 has eliminated the requirement that the CEC determine the fuel composition of imported power.

Figure 5-2. Increase in Coal and Natural Gas Power in Wholesale Power Mix, 1999-2008[183]



PG&E provides T&D service for Direct Access customers. Approximately 7 percent of the electricity supplied in PG&E service territory is supplied to Direct Access customers.[184] As a result, the GHG emission impact of Direct Access power purchases is substantial. Direct Access customers purchase electricity primarily based on lowest price.

5.1.5 GHG Emissions Forecast

PG&E estimates in its *2006 Long-Term Procurement Plan* that, if it achieves all of its *Energy Action Plan* targets and the 20 percent RPS requirement, PG&E GHG emissions will nevertheless increase by 14 to 23 percent by 2016.[185] Assuming the only change in this strategic plan is the achievement of a 33 percent RPS target in 2020, PG&E's GHG emissions in 2020 would be about 3 percent higher than 2010 GHG emissions in a low hydro year, and about 5 percent lower in a normal hydro year.[186,187] The primary reason for little or no reduction in GHG emissions is that projected PG&E load growth consumes much of the renewable energy increment from 20 to 33 percent.

The *PG&E 2010 Long-Term Procurement Plan* has a similar GHG emissions forecast. GHG emissions in 2019 are 7 percent higher than GHG emissions in 2011. GHG emissions in 2020 are 2 percent lower than GHG emissions in 2011.[188]

PG&E will be subject to cap-and-trade GHG emissions reduction requirements under AB 32. AB 32 mandates that California reduce GHG emissions to 1990 levels by 2020 and achieve an 80 percent reduction from 1990 levels by 2050. CARB is required by regulation to develop emission limits and control measures to achieve this GHG reduction objective. Under cap-and-trade, an overall limit on GHG emissions from capped sectors will be established by the cap-and-trade program. Facilities subject to the cap will be able to trade allowances to emit GHGs. The agency has designed an enforceable cap-and-trade program. The program began on January 1, 2012, with an enforceable compliance obligation beginning with the 2013 GHG emissions.[189]

It is unclear whether PG&E will be required to reduce GHG emissions at all by 2020 as a result of CARB cap-and-trade targets for the electricity industry. Other California IOUs and POUs, with a few exceptions, use higher amounts of coal and natural gas-fired power than PG&E and would be the likely first-in-line candidates to reduce GHG emissions under a California electricity GHG cap.[190]

5.2 Business-As-Usual Bay Area GHG Emissions in 2020

Some assumptions had to be made in this report to calculate current Bay Area CO_2 emissions from electricity usage. Estimates were developed for PG&E bundled customers, PG&E Direct Access customers, and POUs. Direct Access customers are presumed to purchase lowest-cost electricity. Lowest-cost electricity would generally be wholesale imported power. Data is available on the fuel mix composition of wholesale imported power. This data allows estimation of a CO_2 emission factor for electricity imports. This factor can also be used to estimate CO_2 emissions from Direct Access customer electricity usage.

Through 2008 the CEC estimated the fuel mix composition of imported power bought by California utilities from wholesale electricity providers or short-term market purchases.[191] The reason stated by the CEC for estimating the imported power fuel mix composition is:[192]

> Since imports represent a significant portion of the electricity supply serving California demand, a *realistic* accounting of associated emissions will be important to design and implement in the greenhouse gas reduction program required under the *Global Warming Solutions Act of 2006* (AB 32). A flawed resource mix estimate may cause unintended market consequences that increase costs and provide no effect on total greenhouse gas emissions.

AB 162 eliminated the requirement that the fuel mix composition of imported power be determined by the CEC.[193,194] The last year the CEC calculated the fuel mix of imported power was 2008. The coal power content of imported power was estimated at 34 percent by the CEC for 2008.[195]

The 2008 composite PG&E CO_2 emission factor for electricity generation is 641 lb CO_2/MWh, or approximately 0.32 tons CO_2/MWh.[196] An emission factor of 0.50 tons CO_2/MWh is used to represent natural-gas fired generation based on 2010 CEC data.[197] Natural gas-fired generation consists of a mix of combined cycle, combustion turbine, and steam boiler generation.

CARB uses a GHG emission factor of 960 lb CO_2/MWh for imported power, equivalent to 0.48 tons CO_2/MWh, in its emissions forecast for the proposed GHG cap-and-trade program.[198] This is the CO_2 emission rate used for imported power in BASE 2020.

The CO_2 emissions estimate for PG&E territory including both bundled and Direct Access customers, and for the Bay Area, is provided in Table 5-1. Bay Area POUs as a group are assumed to have a CO_2 emission rate equivalent to that of PG&E bundled customers. Direct Access customers are presumed to rely primarily on imported power. Total CO_2 emissions for PG&E bundled and Direct Access customers and POU customer CO emissions are estimated at nearly 31 million tons per year in 2008. This CO_2 emission rate is expected to stay relatively constant through 2020 as indicated in PG&E's *2006 Long-Term Procurement Plan*.

Table 5-1. Total Bay Area GHG Emissions from Electricity Consumption in 2008

Source	GWh[199]	CO_2 emission factor (tons/MWh)	2008 CO_2 emissions (million tons)	Bay Area fraction	2008 Bay Area CO_2 emissions (million tons)
PG&E bundled customers	81,983	0.32	26.2	0.6	15.7
PG&E Direct Access customers	6,376	0.48	3.1	0.6	1.8
Bay Area POUs	5,327	0.32	1.7	1.0	1.7
				Bay Area total:	19.2

As shown in Table 5-1, the 2008 baseline year CO_2 emission rate from electricity usage in the Bay Area, including PG&E bundled and Direct Access customers and Bay Area POUs, is about 19 million tons per year. The nine Bay Area counties represent about 60 percent of electricity usage in PG&E service territory, and about 50 percent of usage in the PG&E planning area, which includes POUs.[200]

5.3 PG&E Renewable Energy Strategy

PG&E reached 17.7 percent renewable energy as a percentage of sales in 2010.[201] A significant portion of this renewable energy is generated in the Bay Area. Operational renewable energy resources in the region include geothermal generation at The Geysers in Sonoma County and wind generation in Altamont Pass (Contra Costa and Alameda counties) and Solano County.

PG&E's renewable energy development strategy is to purchase a large amount of output from large-scale solar projects in the Mojave Desert, a substantial quantity of new wind power, and develop 500 MW of distributed multi-MW ground-mounted PV in PG&E service territory.[202]

PG&E has agreed to pay more than the market reference price in 77 percent of the RPS power purchase agreements it has signed.[203] This is despite the PG&E statement in its January 2011 request to rehear the approval of the CPUC's distributed PV RAM program that it is not obligated to pay more than the market reference price for renewable energy. The CPUC projects that ratepayers will pay $6 billion beyond the reference price to meet the terms of renewable energy contracts signed by PG&E, SCE, and SDG&E.[204]

The utility reference case developed by the CPUC assumes that all IOU solar power developed to achieve the 33 percent by 2020 target will be utility-scale remote projects.[205] The availability of federal cash grants and loan guarantees for renewable energy projects under the American Recovery and Reinvestment Act, and preferential "fast track" access to undeveloped Bureau of Land Management (BLM) land, gave strong initial momentum to fast track PG&E solar projects.[206,207] However, as shown in Table 5-2, multiple project cancellations have reduced overall capacity in the fast track pool to just over 2,700 MW. Legal complications for the remaining fast track solar projects, related to concerns over endangered species and Native American cultural sites, have slowed development and created uncertainty over how many projects will be completed.[208]

Table 5-2. Status of Fast Track Solar Projects on BLM Land[209]

Remote solar project	Technology	Capacity (MW)	Status
Ivanpah - PG&E	power tower	370	multiple lawsuits
Ridgecrest	solar trough	~~250~~	cancelled
Genesis - PG&E	solar trough	250	lawsuit
Calico	dish Stirling	~~663~~	cancelled
Blythe	solar trough	~~1,000~~	cancelled
Palen	solar trough	500	lawsuit
Imperial County	dish Stirling	~~709~~	cancelled
Desert Sunlight - PG&E	PV	550	lawsuit
Chevron Lucerne Valley	PV	45	lawsuit
Total large remote solar:		2,715	

5.4 Conclusions and Recommendations

- PG&E is not meeting energy efficiency targets set by the CPUC.

- PG&E is not projected substantial reductions in GHG emissions as a result of reaching a 33 percent RPS target.

- PG&E's renewable energy strategy is imposing substantial above market costs on PG&E ratepayers.

- The CO_2 emission rate from coal power, 1.06 tons CO_2/MWh, is four times higher than the PG&E average CO_2 emission rate from all generation sources of 0.32 tons CO_2/MWh in 2008. Even though coal power provided only 8 percent of electricity sold be PG&E in 2008, coal power CO_2 emissions represented about 30 percent of total PG&E CO_2 emissions from electricity sales.

- AB 162 should be amended to require the CEC to continue to calculate the GHG burden of PG&E wholesale power purchases. Crafting an efficient GHG reduction strategy for electricity generation will be hampered by the lack of precise information on the GHG impact of these power purchases.

6. Comparative Capital Cost and Cost-of-Energy of Generation Technologies

Table 6-1 summarizes 2010 estimated capital cost values, in dollars per kW of installed capacity, and the levelized cost-of-energy (LCOE) production over a 20-year period, for principal renewable energy and conventional power generation technologies. Table 6-1 also includes the estimated cost adders to the LCOE where appropriate for: 1) new transmission, 2) back-up peaking gas turbine capacity for technologies with low availability during summer peak demand, and 3) transmission line losses. The "all-in" LCOE is provided for each technology in the far right column of Table 6-1. PG&E reported actual 2011 RPS contract prices as: 0-to-3 MW PV = $129/MWh, 3-to-20 MW PV = $114/MWh, 20 – 200 MW wind = $118/MWh (See CPUC RPS Quarterly Report – 4th Quarter 2011, Appendix A, p. 4: http://www.cpuc.ca.gov/NR/rdonlyres/3B3FE98B-D833-428A-B606-47C9B64B7A89/0/Q4RPSReporttotheLegislatureFINAL3.pdf).

Table 6-1. Comparative Capital Cost and Levelized Cost-of-Energy (LCOE) of Representative Generation Technologies

	New generation technology	Capacity (MW)	Capital cost[a] ($/$kW_{ac}$)	Capacity factor[a] (%)	O&M cost, incl. fuel ($/MWh)	LCOE generation ($/MWh)	New transmission adder[f] ($/MWh)	Availability at peak[g] (%)	Requires back-up turbines for grid reliability?	Back-up turbine cost adder[j] ($/MWh)	Transmission losses, 5%[k] ($/MWh)	LCOE total ($/MWh)
1	Dry-cooled solar thermal, remote	generic	5,350 – 5,550	20 – 28	30	202	46	77	no	0	12	260
2	Distributed fixed thin-film PV	20	3,600 – 4,000	20 – 27[c]	17 – 25	138[d]	0	50	no[h]	0	0	138
3	Distributed 1-axis track polysilicon PV	20	4,500	23 – 31[c]	20 – 27	135[d]	0	77	no[h]	0	0	135
4	Utility-scale fixed thin-film PV, remote	250	3,600 – 4,000[b]	20 – 27[c]	17 – 25	138[d]	46	50	no[h]	0	9	193
5	Utility-scale 1-axis track polysilicon PV, remote	250	4,500[b]	23 – 31[c]	20 – 27	135[d]	46	77	no[h]	0	9	190

Table 6-1. Comparative Capital Cost and Levelized Cost of Energy (LCOE) of Representative Generation Technologies (cont.)

New generation technology		Capacity (MW)	Capital cost[a] ($/kW$_{ac}$)	Capacity factor[a] (%)	O&M cost, incl. fuel ($/MWh)	LCOE generation ($/MWh)	New transmission adder[f] ($/MWh)	Availability at peak[g] (%)	Requires back-up turbines for grid reliability?	Back-up turbine cost adder[j] ($/MWh)	Transmission losses, 5%[k] ($/MWh)	LCOE total ($/MWh)
6	Onshore wind, remote	200	2,371	33	21	95	46	4/ 29	yes[i]	55/ 25	10/ 8	206 /174
7	Biogas – landfill, local	generic	2,750	80	19	92	0	90+	no	0	0	92
8	Biomass, remote	generic	4,522	85	12	108	16	90+	no	0	6	130
9	Geothermal, remote	generic	6,379	81	5	148	17	90+	no	0	8	173
10	Natural gas combined cycle, remote	500	1,249	65	82	134[e]	21	90+	no	0	8	163
11	Natural gas simple cycle, local	100	1,204	5	150	795	0	90+	no	0	0	795
12	Pulverized coal, remote	1,000	4,000	80	42	112	15	90+	no	0	6	133
13	Nuclear, remote	1,000	7,500	90	47	151	46	90+	no	0	10	207

Table 6-1 notes:

a) Sources of data by generation type (except on-peak availability values): See CPUC Rulemaking R.10-05-006, 2010 Long-Term Procurement Planning (LTPP) proceeding, *Planning Standards for System Resource Plans – Part II, Long-Term Renewable Resource Planning Standards – Attachment 1*, prepared by Energy & Environmental Economics for CPUC, June 22, 2010, Table 1, p. 12, for generation technologies **1, 6, 7, 8, 9.** See Renewable Energy Transmission Initiative (RETI), *RETI Phase 2B Final Report*, May 2010, for generation technologies **2, 3, 4, 5**. See CEC, *Comparative Costs of California Central Station Electricity Generation*, January 2010, for generation technologies **10** and **11**. See Moody's Corporate Finance, *New Nuclear Generating Capacity: Potential Credit Implications for U.S. Investor-Owned Utilities*, May 2008, Table 9, p. 15, for generation technologies **12** and **13**.

b) It is assumed that economies of scale are fully realized at 20 MW and no additional economies are realized in larger PV configurations. This is the implicit assumption in the reference tables in the RETI Phase 2B Final Report, May 2010, Tables 4-7 and 4-8. At the time the RETI Phase 2B Final Report was issued, the largest PV array in the U.S. was 25 MW (FPL). Since publication of the RETI Phase 2B Final Report, Sempra Generation has brought online a 48 MW fixed, thin-film PV array in Boulder City, NV.

c) The highest capacity factor in range is for desert sites. Lowest capacity factor in range is for coastal sites. The fixed PV LCOE assumes a very good to excellent solar site. Examples: Southern California, Central Valley, and inland from East Bay.

d) PV systems prices have fallen significantly since RETI published the referenced LCOE's for distributed PV systems of 20 MW and greater in the RETI Phase 1A Final Report, May 2010. CPS Energy, the San Antonio public utility, signed contracts with SunEdison for three 10 MW PV arrays to be constructed in the greater San Antonio area in October 2007 for $150/MWh. San Antonio has about 10 percent less solar insolation on an annual basis than central California and Southern California coastal areas. The value of the CPS Energy – SunEdison contract, adjusted to the ~10 percent better solar intensity of Central California and Southern California coastal areas, would be about $135/MWh. See: SNL Financial, *In the news - CPS Energy partnering with SunEdison to build three 10 MW solar PV projects in its service area*, October 7, 2010.

e) The estimated LCOE for a conventional merchant 500 MW combined cycle plant in the CEC's *Comparative Costs of California Central Station Electricity Generation*, January 2010, is $124/MWh assuming a 75% capacity factor. Actual capacity factor of California's combined cycle fleet is approximately 65%. The CPUC assumes a 65% capacity factor for combined cycle units in *Inputs and Assumptions to 33% Renewables Portfolio Standard Implementation Analysis,* prepared by E3 for CPUC, July 2009. At a 65% capacity factor, the corrected LCOE for a conventional merchant 500 MW combined cycle plant with a 2009 online date is $134/MWh. For a 2018 online date, $183/kWh is projected by the CEC. The CPUC's MPR for a 20-yr power purchase agreement with start date of 2011 is $101/MWh at 92% capacity factor. The $101/MWh MPR value includes a $6/MWh CO_2 emissions charge.

f) The CPUC estimates a new transmission annual cost of $1.27 billion per year to transmit 36,870,000 MWh/year of new remote solar and wind resources by 2020. See: CPUC, *33% Renewables Portfolio Standard Implementation Analysis Preliminary Results,* June 2009, Tables 4 and 5, pp. 21-22. This is equivalent to a cost of $34.45/MWh for solar and wind resources transmitted over these lines. The CPUC assumes amortization of transmission capital expense over 40 years, while it amortizes renewable generation over 20 years. To level the investment cost recovery period between generation and transmission projects to allow an "apples-to-apples" annualized cost comparison, the new transmission costs are adjusted in BASE 2020 to a 20-year amortization period. This results in an adjusted transmission penalty of $46.34/MWh (the amortization factor changes from 0.1246 for 40 years to 0.1676 for 20 years) using the RPS Calculator developed by Energy & Environmental Economics, Inc. for the CPUC. The assignment of a transmission cost of $0/MWh to 20 MW distributed PV arrays assumes these arrays are near load centers and are interconnected to the 12 kV distribution system. Remotely located 20 MW PV arrays would require either existing transmission or new transmission to reach demand centers. It is assumed for calculation purposes that the average capacity factor of solar and wind resources used to develop the CPUC transmission cost estimate is 30%. For load-following (combined cycle) or baseload resources, new transmission expense is scaled to account for the higher capacity factor. For example, in the case of a combined cycle unit with a 65% capacity factor, the adjusted new transmission penalty is: (30%/65%) x $46/MWh = $21/MWh.

g) On-peak availability factors for solar thermal (77%), tracking PV (77%), onshore wind (29%) are from Energy & Environmental Economics, Inc., *Inputs and Assumptions to 33% Renewables Portfolio Standard Implementation Analysis*, prepared for CPUC, July 2009, Table 7, p. 12. Onshore wind (4%) is from PG&E's *2006 Long-Term Procurement Plan*, Order Instituting Rulemaking to Integrate Procurement Policies and Considering Long-Term Procurement Plans – Volume I, Public Version Redacted, p. IV-77. On-peak availability factor for fixed PV (minimum 50%) is from Itron, *CPUC Self-Generation Incentive Program—Ninth-Year Impact Evaluation Report – Final Report,* submitted to PG&E, June 2010, Table 5-14, p. 5-32. PG&E peak hour fixed PV capacity factor in 2009 was 54%, July 14, 2009, 4 pm to 5 pm. All baseload units, including biomass, geothermal, combined cycle, simple cycle, coal, and nuclear, are assumed to have 90+ % availability at peak. Recent natural gas-fired applications for Bay Area projects, including Marsh Landing, Russell City Energy Center, Oakley, and Mariposa Energy Center, state expected availability in the range of 92 to 98%. Coal plant applicants around the country typically identify an availability design target of 90%. Nuclear plants reach 90%+ availability in years when refueling outages or major maintenance outages do not take place.

h) Analysis of hourly cloud cover and global irradiance data at the Oakland and San Jose airports during the top CAISO control area 100 peak one-hour demand events in 2007 shows little or no cloud cover in the Bay Area during peak demand events. This means that solar PV is reliably available during peak demand periods. This phenomenon is discussed in more detail in Chapter 7.

i) Wind power, unlike solar power, is generally not available during summer afternoon peak periods. For this reason, utilities typically use wind power as justification for adding gas turbines for reliability support. Battery storage can serve this same purpose. For cost calculation purposes, the added cost of back-up peaking gas turbine capacity is included in the LCOE for wind power provided in the table.

j) This cost adder represents the amount of back-up gas turbine capacity necessary for wind power to attain the 50% on-peak availability of fixed PV, assuming an on-peak availability for wind of either 4% (PG&E estimate) or 29% (CPUC estimate). The 2009 LCOE for new peaking turbine capacity at 5% capacity factor is $795/MWh. See: CEC, *Comparative Costs of California Central Station Electricity Generation*, January 2010, Table 4. A 200 MW wind farm, at a capacity factor of 33%, will generate 0.33 x 8,760 hr/yr x 200 MW = 578,160 MWh/yr. At a 4% on-peak capacity factor, the 200 MW wind farm will produce 8 MW on-peak and require 92 MW of peaker turbine back-up to match the 50% on-peak availability of fixed PV capacity. At a 5% capacity factor, 92 MW of peaking gas turbine capacity will have an annual cost of: 0.05 x 8,760 hr/yr x $795/MWh x 92 MW = $32 million/yr. The back-up peaker turbine adder in this case would be: $32 million/yr ÷ 578,160 MWh/yr = $55/MWh. At a 29% on-peak capacity factor, the 200 MW wind farm will produce 58 MW on-peak and require 42 MW of peaker turbine back-up to match the 50% on-peak availability of 200 MW of fixed PV capacity. At a 5% capacity factor, 42 MW of peaking gas turbine capacity will have an annual cost of: 0.05 x 8,760 hr/yr x $795/MWh x 42 MW = $14.6 million/yr. The back-up peaker turbine cost adder in this case would be: $14.6 million/yr ÷ 578,160 MWh/yr = $25/MWh.

k) The RETI Cost Calculator spreadsheet for renewable energy LCOE calculations assumes an average 5 percent transmission line loss, of total T&D losses, for remote renewable generation. See: http://www.energy.ca.gov/reti/documents/phase2B/CREZ_name_and_number.xls.

7. Peak Demand and Renewable Energy Profiles

A generic California summertime 24-hour demand profile and power mix are shown in Figure 7-1. Demand generally peaks in the mid-afternoon. The generation units that supply this demand consist of: baseload facilities like the Diablo Canyon nuclear plant, hydroelectric units, geothermal and biomass plants; energy purchases from the wholesale Western power market, including coal plant output; intermediate and load following natural gas combined cycle units like Gateway and Colusa; and high-cost peaking gas turbines.

Figure 7-1. Power Mix Stack to Meet California Peak Load[210]

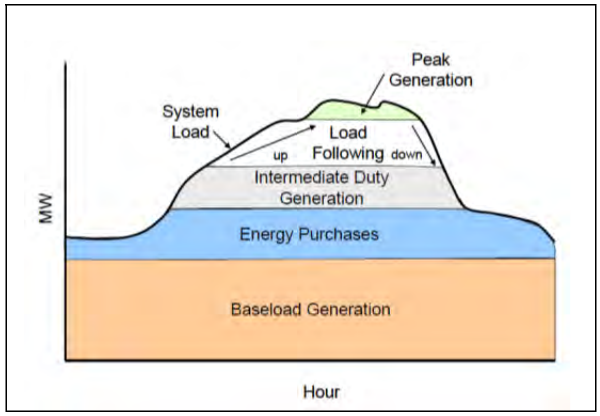
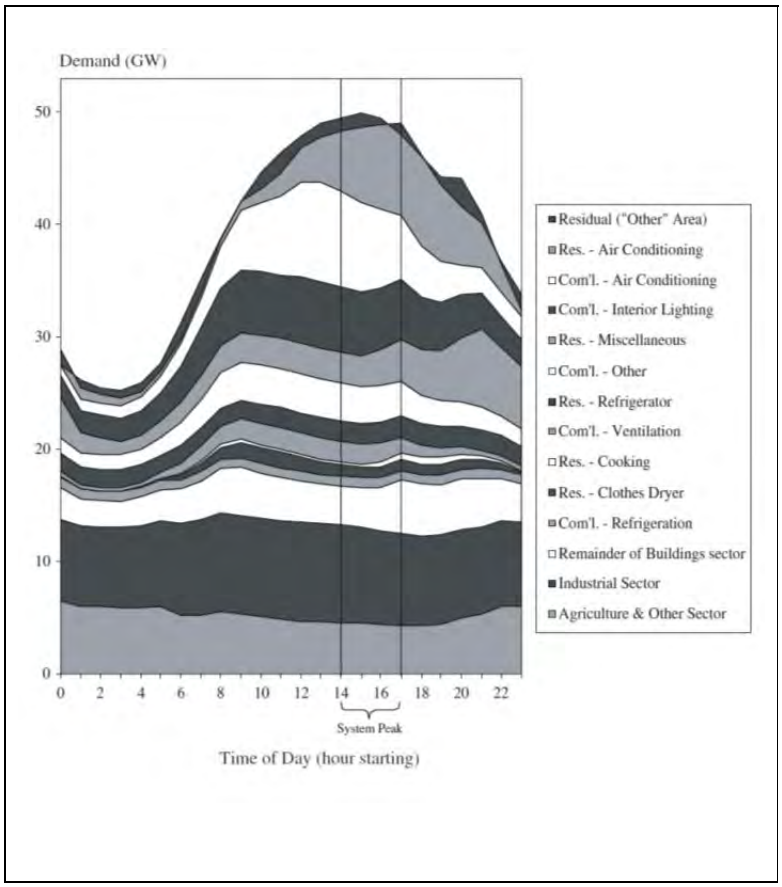


Figure 7-2 shows the sources of demand on California peak summer days. Air conditioning is the nearly exclusive additional summertime load, accounting for more than 30 percent of total load at the peak hour. Statewide load can increase at a rate of 4,000 to 5,000 MW per hour on peak summer days.

Utilities justify the construction of new generation and transmission assets based on projections of increased demand over time and potential shortages of electricity in the future if new assets are not brought online. The top few hours of demand drive this process. Any solution that eliminates growth in demand also eliminates the justification for authorizing the construction of new conventional generation and transmission infrastructure.

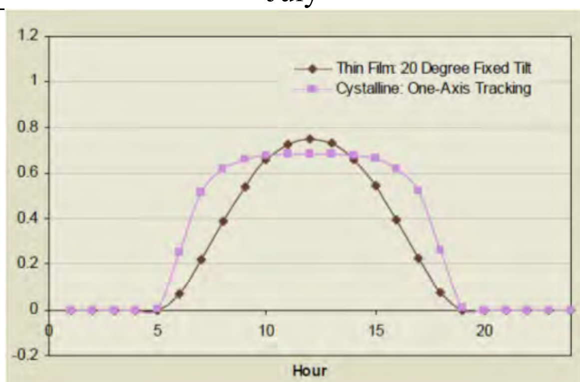
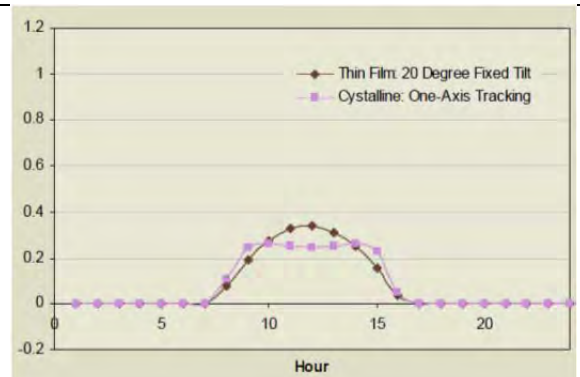
Figure 7-2. Summer 24-Hour Demand Profile in California and Sources of Demand[211]



7.1 PV Summer and Winter Output Profiles

The output of fixed PV systems is a reasonably good match for the summer peak load profile as can be seen in the July PV profile in Figure 7-3. In California the July profile is shifted one to the right, centered over 1 pm, due to the seasonal time change. The PG&E one-hour summer peak occurs consistently between 1 pm and 5 pm. In the 4 pm to 5 pm hour on a clear day, the fixed PV system is still generating over 50 percent of its rated capacity. A tracking PV system is generating about 80 percent of its rated capacity in the 4 pm to 5 pm hour.

Figure 7-3. Output Profiles of PV Systems in July and December[212]

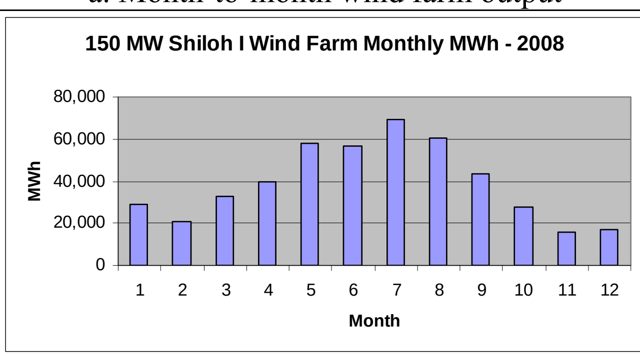
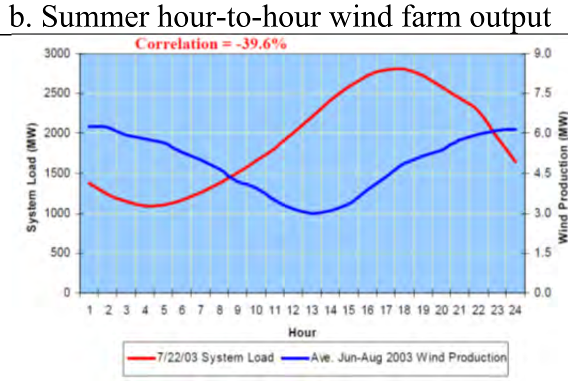
July	December
	

7.2 Solano County Wind Output Profiles

The wind production pattern in the Bay Area's largest and growing wind development area in Solano County is a good match to demand on a seasonal basis. Altamont Pass was the original focus of wind development in the Bay Area in the 1980s and 1990s. However, the Altamont wind resource is not as strong as Solano County wind, and there is little new development.

As shown in Figure 7-4a, Solano County wind farms are most productive in summer. However, wind output on an hour-to-hour basis does not track summertime peak demand. Output is at a minimum from noon to 3 pm, and then steadily increases. This characteristic is shown in Figure 7-4b.

Figure 7-4. Annual and Summer Day Output of Wind Power in Solano County[213,214]

a. Month-to-month wind farm output	b. Summer hour-to-hour wind farm output
	

7.3 Projected Demand - Electric Vehicles

PG&E indicates that it would take millions of plug-in hybrid electric vehicles (PHEVs) charging nightly on PG&E's system before there would be any concern about the need for additional off-peak procurement because of the large amount of excess generation available at night.[215]

The company projects that by 2015 the expected level of PHEVs in California will be about 75,500, with an upper-end achievable level by 2015 of 1,625,000 PHEVs.[216]

The Nissan Leaf is a representative PHEV available in the California market. The Nissan Leaf travels about 3.4 miles per kWh.[217] Assuming the average vehicle travels an average of 10,000 miles per year, the owner of the Leaf would require about 8 kWh of electricity per day of vehicle use.[218]

PG&E also indicates that PHEV vehicles, and electric substitution in a wide range of on-road and non-road vehicle applications, represent a potential total peak demand on PG&E's system of 250 to 380 MW by 2020 under the expected scenario.[219]

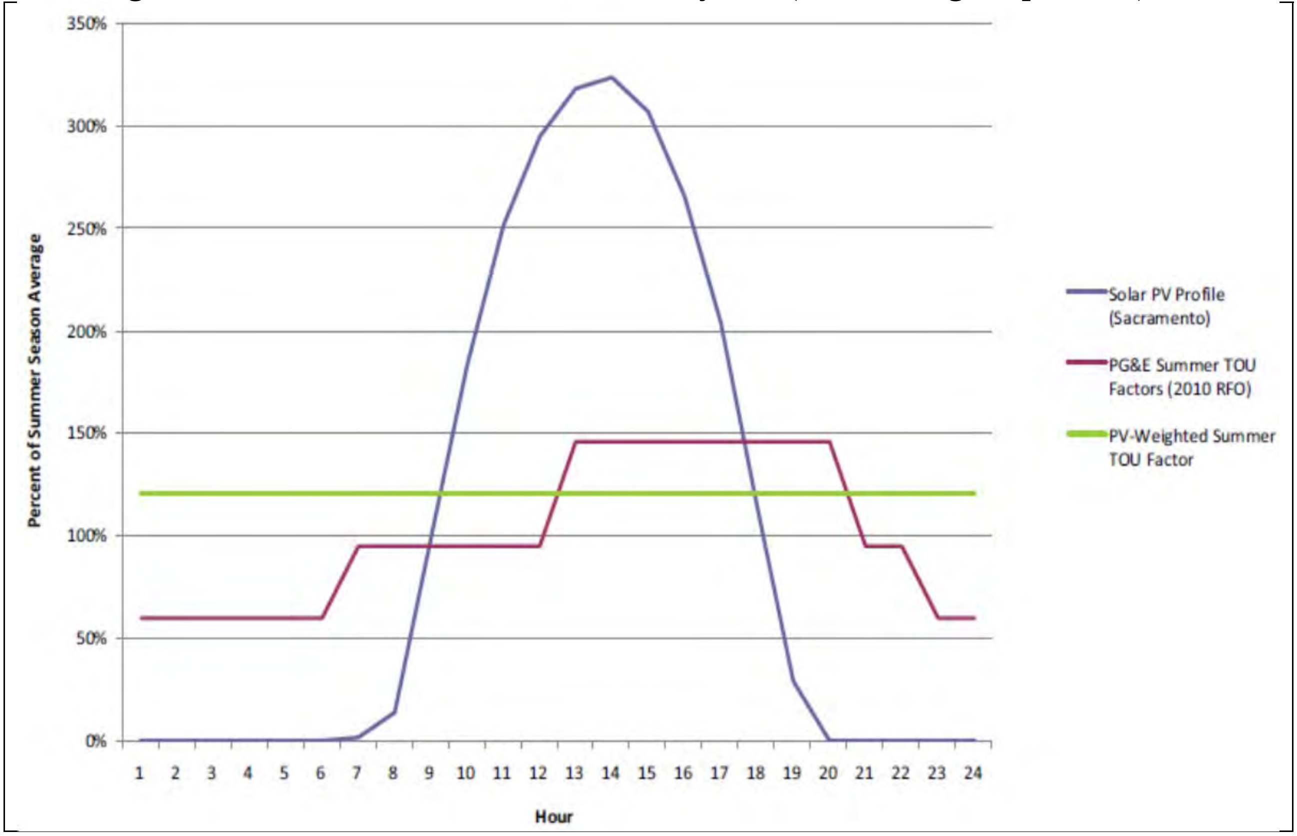
As addressed in Chapter 10, the large quantity of PV online in 2020 under BASE 2020 will result in high levels of PV generation, and reduced electricity prices, at mid-day. Charging PHEVs in the middle of the day will be both economic and serve the critical grid function of absorbing excess non-dispatchable mid-day PV generation.

7.4 Value of Electricity Varies with Time of Day

Electricity demand is lowest at night, on the weekends, and in winter. During these times there is an abundance of generating resources available and only least-cost generators are online. As the demand increases on hot summer workdays, progressively more expensive generation resources are brought online to meet demand. Utilities meet some of their demand requirements with wholesale power market purchases. All generators selling into the wholesale power market in any given hour receive the highest bid payment accepted in that hour. During peak hours on hot days, when high-cost peaking turbines are selling into the market, accepted bid prices may reach $1,000 per MWh.[220,221]

The output of a PV system roughly corresponds to the electricity demand periods when hour-to-hour summer electricity prices are highest, as shown in Figure 7-5. PG&E sets different tariffs for different times of day (purple line). These are known as "time-of-use" (TOU) tariffs. The average value of electricity during the periods when PV is generating is significantly higher over the course of a year than the average value of electricity over all the hours of the year.

Figure 7-5. Solar PV Profile on the PG&E System (June through September) [222]



The "time-of-delivery" (TOD) is the period when electricity is being delivered to the grid by the PV system. The TOD factor that PG&E applies to PV is 1.24. However, SCE applies a TOD factor for PV of 1.32. SDG&E applies a factor of 1.12.[223] The wide variability in these TOD factors has raised concerns about the advisability of using these factors uncritically to determine the value of PV, as noted by solar industry advocates in 2010 testimony before the CPUC:[224]

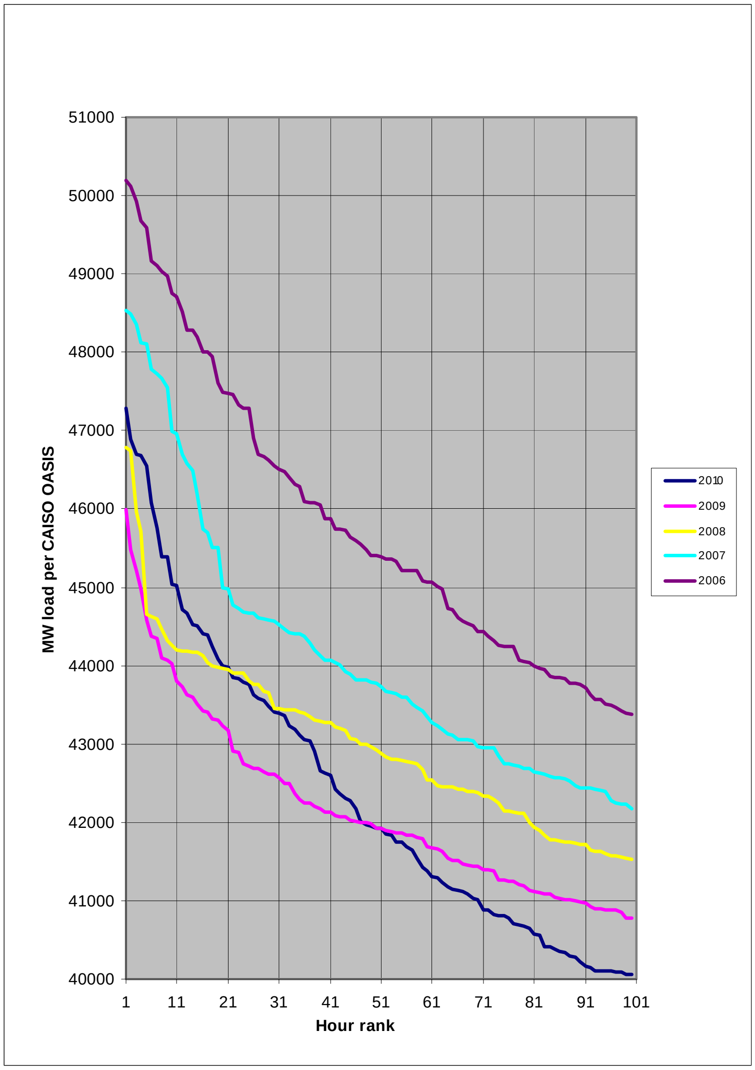
> Over time, it has become very clear that the IOUs' (summer on-peak time-of-delivery) TOD factors are problematic – they are not transparent, they vary widely from utility to utility even though the utilities operate in closely-linked markets . . . Even (The Utility Ratepayer Network) TURN acknowledges that the IOUs' TOD factors are not consistent.

7.5 Peak Loads Decline Rapidly

The CAISO control area consists of the combined service territories of PG&E, SCE, and SDG&E. Figure 7-6 shows how quickly the demand in the CAISO control area declines from the highest peak hour of the year to the one-hundredth highest peak hour of the year. As shown in the graphic, the load drops 5,000 to 7,000 MW for the highest hour to the one-hundredth hour. PG&E, SCE, and SDG&E collectively provide about two-thirds of the electricity used in California. Therefore, assuming the CAISO load decline pattern is representative for other electricity providers in California, the statewide load decline across the highest 100 peak hours of the year would be in the range of 7,500 to 10,500 MW.

The portion of this CAISO load decline that occurs in the first 10 peak hours has been substantial in recent years, specifically 2008, 2009, and 2010, ranging from 2,000 to 3,000 MW. Extrapolated to California as a whole, this equates to a decline in the first 10 peak hours of 3,000 to 4,500 MW.

Figure 7-6. CAISO Load-Duration Curves for Top 100 Hours of Year, 2006 - 2010[225]



7.6 PV Very Reliable at Peak Load

Global irradiance, also known as solar insolation, is a measure of the solar intensity at the earth's surface at a specific site at a specific time of day. Clouds reduce the amount of irradiance reaching the earth's surface. Powers Engineering selected two representative Bay Area airports, Oakland and San Jose, as sample sites to evaluate whether cloud cover had a significant impact on PV system output on peak demand days in the Bay Area.

Summer of 2007 hour-by-hour global irradiance data and hour-by-hour cloud cover data was analyzed for the Oakland and San Jose airport sites.[226,227] 2007 was selected as the study year because hour-by-hour global irradiance data is publicly available for 2007 at no cost. Actual expected hour-to-hour global irradiance at specific sites is determined from weather satellite images that record cloud density. The actual modeled irradiance at the Oakland and San Jose Airports was divided by the clear day global irradiance expected for the same day and hour at each of those sites to calculate the reduction in solar intensity due to clouds.

The results of this comparison are that cloud cover was not a significant factor during the highest peak demand hours of the year in the Bay Area. As shown in Table 7-1, the solar resource was fully available in the Bay Area for the top 5,000 MW of peak load events in PG&E territory in 2007, from 21,230 MW down to 16,344 MW. The Bay Area solar resource is highly reliable during peak demand periods. A summary of this analysis is provided in Appendix D.

Table 7-1. Summer 2007 Peak Hour Solar Resource Availability in Bay Area

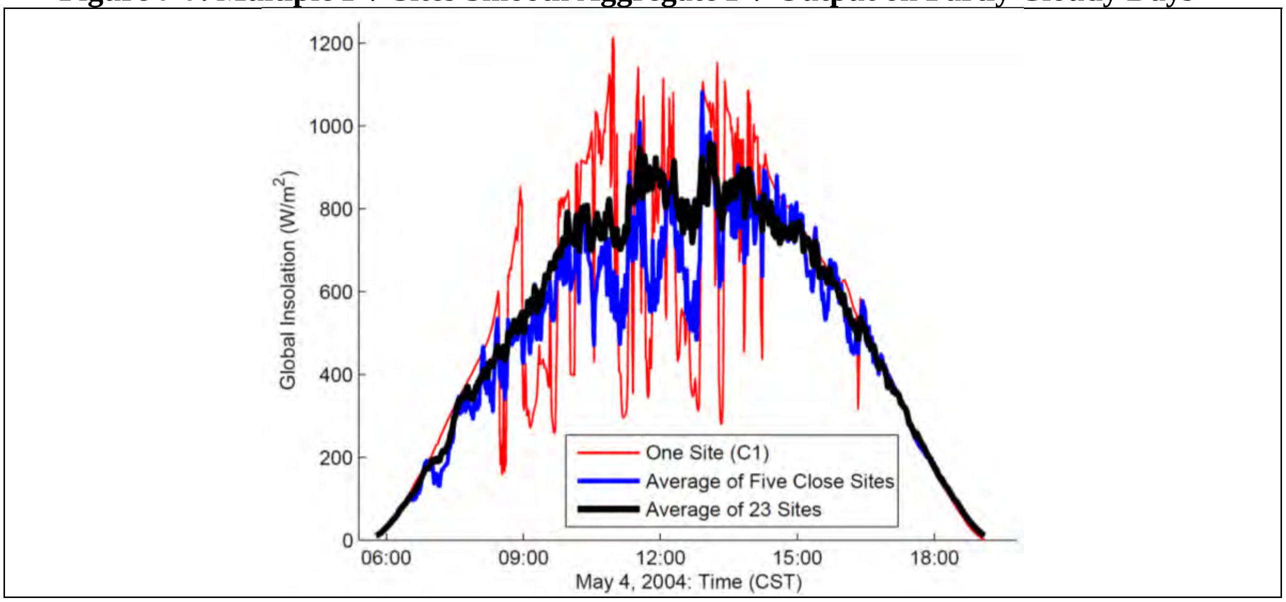
Day and hour of CAISO peak load	CAISO peak load (MW)	PG&E peak load (MW)	% of clear day global irradiance, Oakland Airport	% of clear day global irradiance, San Jose Airport
8/29/07, HE16	48,553	21,230	103	99
7/05/07, HE17	44,696	21,184	98	99
8/31/07, HE16	48,823	20,553	103	98
8/30/07, HE15	48,074	20,489	111	98
8/22/07, HE15	43,478	19,807	100	100
6/14/07, HE15	40,895	19,778	100	100
7/06/07, HE15	43,696	19,758	99	100
8/28/07, HE16	46,033	19,651	99	102
8/21/07, HE16	44,707	19,380	103	100
8/23/07, HE14	42,195	19,100	100	102
8/03/07, HE16	42,952	18,901	99	100
7/31/07, HE14	41,834	18,900	100	100
8/01/07, HE15	41,710	18,475	92	100
9/01/07, HE15	44,758	18,443	100	101
8/20/07, HE16	44,294	18,411	100	99
8/24/07, HE15	41,325	18,290	101	100
8/02/07, HE16	42,113	18,268	99	99
7/03/07, HE15	42,748	17,993	99	101
8/27/07, HE15	42,245	17,715	100	100
9/02/07, HE15	43,940	17,626	100	100
9/03/07, HE14	44,874	17,588	100	100
9/05/07, HE14	41,114	17,260	100	100
8/15/07, HE16	43,481	17,218	100	99
8/14/07, HE16	42,889	17,084	100	99
7/02/07, HE16	41,485	16,935	100	104
8/13/07, HE16	41,996	16,782	100	100
9/04/07, HE14	44,616	16,731	99	98
8/16/07, HE15	42,951	16,647	100	101
8/17/07, HE15	42,439	16,344	100	100

HE = hour ending

7.7 PV Performance on Partly Cloudy Days

A 2010 analysis conducted by Lawrence Berkeley National Laboratory determined that, even on partly cloudy days, the aggregate output from dispersed PV systems would follow a relatively smooth bell-shaped curve similar to a clear day PV profile, though with lower output depending on the density of cloud cover. This is an important finding, as one argument used against PV systems is the potential for a cloud to drop output from rated capacity to near zero in a matter of seconds. There are already thousands of PV systems spread over thousands of square miles in the Bay Area. As a result, partly cloudy conditions would cause little PV output variability in aggregate on a minute-to-minute or hour-to-hour basis. The modeled variability of PV system output on partly cloudy days relative to clear days, correlated to the number and distribution of PV sites, is shown in Figure 7-7.

Figure 7-7. Multiple PV Sites Smooth Aggregate PV Output on Partly Cloudy Days[228]



The reality of PV system output variability in regions that already have thousands of PV systems dispersed over a wide area, like the Bay Area and PG&E service territory, was summarized in a November 2010 article in Renewable Energy World:[229]

> Clouds don't cause that much variability if the PV is spread out over a wide enough area, and because they are visible, it's relatively straightforward to predict the impact on power generation on a short-term basis and even easier to predict the amount of power that will be generated the next day based on weather reports. That's fine because power markets operate on a day-to-day basis.
>
> Dan Shugar, CEO of Solaria (Fremont), a supplier of PV modules, said: "In PG&E's territory alone, which is pretty much north of LA up to Oregon, there's about 30,000 solar plants. If you look at a 10 x 10 mile area, statistically there's no variability."

7.8 Wind Energy and Need for Back-Up Power

PG&E states that gas turbine power plants are needed as back-up power to assure grid reliability when the wind does not blow and the sun does not shine.[230] However, during the hottest days of the year, the sun reliably shines. Leaving aside the issue of PG&E's current large margin of excess capacity, some form of backup power, either energy storage or gas turbine, would be necessary for a utility with a renewable portfolio that relies heavily on wind power. It is straightforward to calculate the additional cost of backup power necessary so that wind generation can equal the reliability of fixed PV on hot summer days. This cost must be added to the LCOE of a wind project to accurately reflect the true cost of wind power compared to PV. The LCOE of new peaking gas turbines estimated by the CEC is shown in Table 7-2.

Table 7-2. LCOE of New Peaking Gas Turbines[231]

Combustion turbine (MW)	Capacity factor (%)	LCOE 2009 ($/MWh)	LCOE 2018 ($/MWh)
50	5	844	1,009
100	5 795		951

This cost adder represents the amount of back-up gas turbine capacity necessary for wind power to attain the 50 percent on-peak availability of fixed PV, assuming an on-peak availability for wind of either 4 percent (PG&E estimate) or 29 percent (CPUC estimate). The 2009 LCOE of new peaking turbine capacity at 5 percent capacity factor is $795/MWh. A 200 MW wind farm, at a capacity factor of 33 percent, will generate 0.33 x 8,760 hr/yr x 200 MW = 578,160 MWh/yr.

At a 4 percent on-peak capacity factor, the 200 MW wind farm will produce 8 MW on-peak and require 92 MW of peaking turbine back-up to match the 50 percent on-peak availability of fixed PV capacity. At a 5 percent capacity factor, 92 MW of peaking gas turbine capacity will have an annual cost of: 0.05 x 8,760 hr/yr x $795/MWh x 92 MW = $32 million/yr. The back-up peaking turbine adder in this case would be: $32 million/yr ÷ 578,160 MWh/yr = $55/MWh.

At a 29 percent on-peak capacity factor, the 200 MW wind farm will produce 58 MW on-peak and require 42 MW of peaker turbine back-up to match the 50 percent on-peak availability of 200 MW of fixed PV capacity. At a 5 percent capacity factor, 42 MW of peaking gas turbine capacity will have an annual cost of: 0.05 x 8,760 hr/yr x $795/MWh x 42 MW = $14.6 million/yr. The back-up peaker turbine adder in this case would be: $14.6 million/yr ÷ 578,160 MWh/yr = $25/MWh.

7.9 Rooftop PV Meets Same Need as Peaking Turbine

The CEC denied an application for a 100 MW natural gas-fired peaking gas turbine plant, the Chula Vista Energy Upgrade Project (CVEUP) in San Diego County, in June 2009. The application was denied in part because the CEC opined that rooftop PV could potentially achieve the same objectives for comparable cost.[232]

This June 2009 CEC decision implies that any future applications for gas-fired generation in California should be measured against using urban PV to meet the power need. This logic would also apply to other types of generation, including remote utility-scale solar energy, that would fill the same power supply niche as urban PV. The final CEC decision in the CVEUP proceeding states:[233]

> Photovoltaic arrays mounted on existing flat warehouse roofs or on top of vehicle shelters in parking lots do not consume any acreage. The warehouses and parking lots continue to perform those functions with the PV in place. (Ex. 616, p. 11.)….Mr. Powers (expert for intervenor) provided detailed analysis of the costs of such PV, concluding that there was little or no difference between the cost of energy provided by a project such as the CVEUP (gas turbine peaking plant) compared with the cost of energy provided by PV. (Ex. 616, pp. 13 – 14.)….PV does provide power at a time when demand is likely to be high—on hot, sunny days. Mr. Powers acknowledged on cross-examination that the solar peak does not match the demand peak, but testified that storage technologies exist which could be used to manage this. The essential points in Mr. Powers' testimony about the costs and practicality of PV were uncontroverted.

The CEC concluded in the CVEUP final decision that PV solar arrays on rooftops and over parking lots may be a viable alternative to the gas turbine project proposed in that case, and that if the gas turbine project proponent opted to file a new application a much more detailed analysis of the PV alternative would be required.

7.10 Conclusions and Recommendations

- Wind farm output is not a good match for summer peak demand hours.
- PV systems are reliably available during summer peak demand hours.
- Large numbers of widely distributed PV systems would experience little output variability in aggregate under partly cloudy conditions.
- The cost of back-up peaking turbine capacity to address the relative lack of availability of wind power during peak demand hours adds $25 to $55/MWh to the net LCOE of wind generation, relative to distributed PV generation, depending on the assumed wind power capacity factor at peak.
- The reliability of distributed PV systems on hot summer afternoons means that distributed PV systems can serve the same peak power supply role as peaking gas turbines to meet summer afternoon peak loads.

8. Achieving Energy Efficiency Reductions

California has been a leader in energy efficient building standards since the 1970s. The CEC estimates that California's building efficiency standards, along with those for energy efficient appliances, have saved more than $56 billion in electricity and natural gas costs since 1978.[234]

However, California is no longer the top-ranked state in energy efficiency. The American Council for an Energy-Efficient Economy ranks Massachusetts as first among states on its 2011 Energy Scorecard.[235] California had ranked first the four previous years. Massachusetts spends about double per customer compared to California, $61 per customer to $32 per customer, on energy efficiency measures. In 2012, Massachusetts will reduce its electricity demand 2.4 percent, while demand in California is expected to decline by 1 percent.[236]

Real energy efficiency reductions of 30 percent are achievable and cost-effective for homes and businesses. The tools available to achieve an average energy efficiency reduction of 30 percent are examined in this chapter.

8.1 Residential and Commercial Electricity Demand

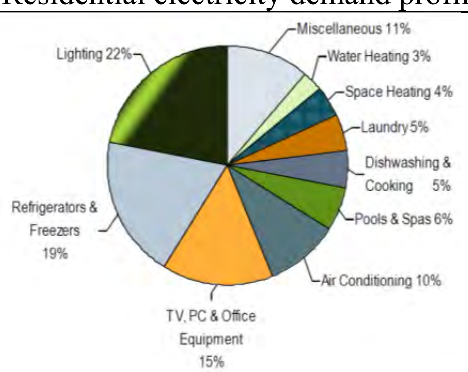
The California residential sector, 12.6 million households in 2008, represents approximately 32 percent of total state electricity consumption. The residential sector represents 36 percent of total state natural gas consumption.[237]

California has more than 5 billion square feet of commercial building space. This category includes office buildings, stores, restaurants, warehouses, schools, hospitals, and public buildings. Commercial buildings account for 38 percent of the state’s electricity use and over 25 percent of natural gas consumption. Four electric end uses, lighting, cooling, refrigeration, and ventilation, account for 75 percent of all commercial electricity use. Three of these - space heating, water heating, and cooking - account for over 90 percent of gas use.[238]

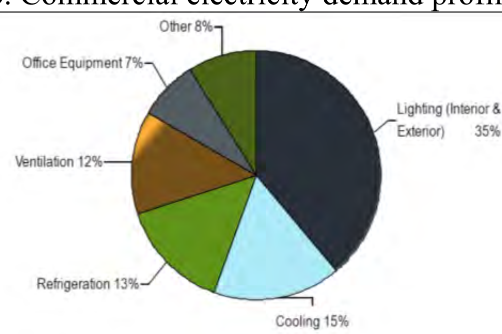
Profiles of residential and commercial electricity demand are provided in Figure 8-1.
The industrial sector accounts for 16 percent of statewide electricity use and 33 percent of natural gas use.[239]

Figure 8-1. Profiles of California Residential and Commercial Electricity Demand[240]

a. Residential electricity demand profile



b. Commercial electricity demand profile



8.2 *Achieving Energy Efficiency Reductions*

8.2.1 Building Standards

The Title 24 energy efficiency standards for residential and commercial buildings were established in 1978 in response to a legislative mandate to reduce California's energy consumption. The standards are updated periodically to incorporate new energy efficiency technologies and methods. The 2008 Title 24 standards, the most recent version of Title 24, went into effect on January 1, 2010.

Local governments in California can adopt building standards more stringent than state and federal mandates. Both San Francisco and Los Angeles have adopted green building ordinances for new buildings. However, relatively few other local governments have adopted local ordinances that exceed Title 24 requirements.[241]

Local governments can also adopt point-of-sale requirements. Berkeley has had residential and commercial building ordinances requiring basic efficiency improvements, triggered at the time of property sale or significant renovations, for over two decades. Sacramento and San Francisco have applied similar requirements at various times.

AB 1103 (2007) requires that a nonresidential building owner or operator disclose Energy Star Portfolio Manager benchmarking data and ratings for the most recent 12-month period to a prospective buyer, lessee, or lender. All nonresidential buildings subject to AB 1103 must comply beginning on January 1, 2013.[242]

California's IOUs have ratepayer-funded programs to demonstrate the cost-effectiveness of energy efficiency, demand response, and onsite renewable generation technologies. PG&E has the *Market Integrated Demand Side Management Initiative*.[243] SCE and SDG&E promote the energy efficiency potential of new and remodeled commercial buildings through *Sustainable Communities* programs.[244]

One of the projects described on the SDG&E Sustainable Communities Program website is a model for the commercial building retrofits that would occur under BASE 2020. X-nth, Inc. of San Diego (formerly TKG Consulting Engineers, Inc.), was recognized by SDG&E for achieving a 30 percent reduction in energy usage beyond the California new building energy efficiency standard.[245] In regard to this retrofit project, SDG&E notes, "TKG's office building is a model for other San Diego County projects. It demonstrates that energy efficiency, occupant comfort, and environmentally friendly design is cost-effective, and can be achieved even with a tight construction schedule."[246]

The energy efficiency of the X-nth, Inc. building was improved by: 1) adding insulation to the interior of the existing concrete walls, 2) adding a film to the existing single glazed windows, 3) use of a variety of high efficiency lighting strategies, 4) occupancy sensors for private offices, 5) and use of a high efficiency air conditioning system. SDG&E also installed a 40 kW PV array on the roof of the X-nth, Inc. building.

New residential and commercial developments designed for zero net energy (ZNE) consumption are being built. For example, in 2007 Austin, Texas established a requirement that all new homes be ZNE capable by 2015.[247] A new urban residential ZNE development has been built in Austin.[248] All homes in the development are ZNE capable. Planned rooftop PV has been installed on some units to date to achieve ZNE consumption.

The first phase of a large new ZNE commercial development at UC Davis, West Village, became operational in January 2012. All phases will be completed in 2013. West Village is a mixed residential and commercial development for 3,000 people. It incorporates advanced energy efficiency measures and 4 MW of rooftop and parking lot PV systems.[249]

California schools have been pioneers in achieving ZNE through energy efficiency and rooftop PV. For example, the Helios Project has developed a Solar Master Plan for schools in the East Bay Area.[250] Schools are in position to take advantage of low-interest federal bonds, low-interest state loans, and grants from regional agencies to reduce energy consumption or GHG emissions. The Helios Project has successfully advocated for the installation of over 750 kW of rooftop PV on East Bay schools, and is working on the installation of another 800 kW. In addition, Helios has identified the total potential capacity of 38 MW of rooftop PV on schools in Berkeley, Oakland, and in West Contra Costa County.[251]

8.2.2 Lighting

California's strategic energy efficiency plan targets a 60 to 80 percent reduction in statewide lighting energy use by 2020. AB 1109 requires California to reduce average statewide electrical energy consumption by not less than 50 percent from the 2007 levels for indoor residential lighting and not less than 25 percent from the 2007 levels for indoor commercial and outdoor lighting by 2018. This legislation is a core element in the effort to achieve the 60-80 percent reduction in lighting energy consumption by 2020.[252]

8.2.3 Refrigerator/Freezer

Refrigerator energy efficiency is regulated by federal government standards. Refrigerators have become much more efficient over the past 20 years. More effort does need to be directed at further reducing refrigerator electricity demand. Current refrigerators use 60 percent less electricity on average than 20-year-old models.[253]

PG&E does have a recycling program for older refrigerators and freezers that includes a modest payment along with free hauling. PG&E will pick up units that are 10 years old or more and pay the customer $35 for recycling the unit.[254]

8.2.4 Air Conditioning

A major element of the state's *Energy Efficiency Strategic Plan* is to advance residential and small commercial heating, ventilating, and air conditioning systems to ensure optimal equipment performance. The plan targets a 50 percent improvement in efficiency of heating, ventilating, and air conditioning systems by 2020, and a 75 percent improvement by 2030. Air conditioning loads are the cause of over 30 percent of California's total peak power demand in the summer. Meeting this load has a costly impact in the form of additional generation, transmission, and distribution resources.[255]

PG&E relies on an Itron analysis of energy efficiency measures in evaluating its energy efficiency performance.[256] Itron largely avoids the issue of increasing the efficiency of central air conditioning units, by stating that the 2006 federal standard for new units is Seasonal Energy Efficiency Ratio (SEER) 13 and the highest SEER rating of economical central air conditioning units is 14.[257] Itron goes on to state there is little difference between SEER 13 and SEER 14 in terms of efficiency, and therefore no economic justification for upgrading from SEER 13 to SEER 14.

However, the average SEER rating for in-use central air conditioning units in California is approximately SEER 10, not the 2006 federal minimum standard of SEER 13 for new units.[258] Competitively-priced central air conditioning units with ratings as high as SEER 21 are commercially available. There is about a 20 percent installed price difference between a SEER 13 or 14 unit and a SEER 21 unit. An incremental energy efficiency improvement of nearly 30 percent is realized by selecting a SEER 21 unit over SEER 13 when compared to the SEER 10 basecase.[259] Itron does acknowledge that major energy efficiency reductions can be achieved in residential and commercial heating and air conditioning systems, though in the context of emerging technology instead of off-the-shelf technology.[260]

Itron does not address new thermal storage air conditioning systems now on the market which could nearly eliminate cooling-related peak demand if installed in new and existing buildings. The Southern California Public Power Authority (SCPPA) has contracted with Ice Energy for 53 MW of ice storage air conditioning units. SCPPA will install more than 6,000 Ice Bear units at 1,500 government and commercial buildings in its member communities.[261] Most of the units are being installed at existing buildings. Graphs of the peak cooling demand reduction achieved by these commercially available thermal storage systems are presented in Appendix E.

Substantial peak load reduction can also be achieved by upgrading existing commercial and institutional cooling systems. Many commercial buildings use electric motor-driven centrifugal chillers to provide cooling. Centrifugal chillers typically consume more electricity than any other single device in a commercial building.[262] The California Center for Sustainable Energy has conducted hundreds of energy efficiency evaluations on chillers. Over 90 percent of these systems operate with relatively low efficiency, in the range of 1.0 to 1.2 kW/ ton of cooling, using oversized pumps, constant speed equipment, and controls that do not work well.[263,264]

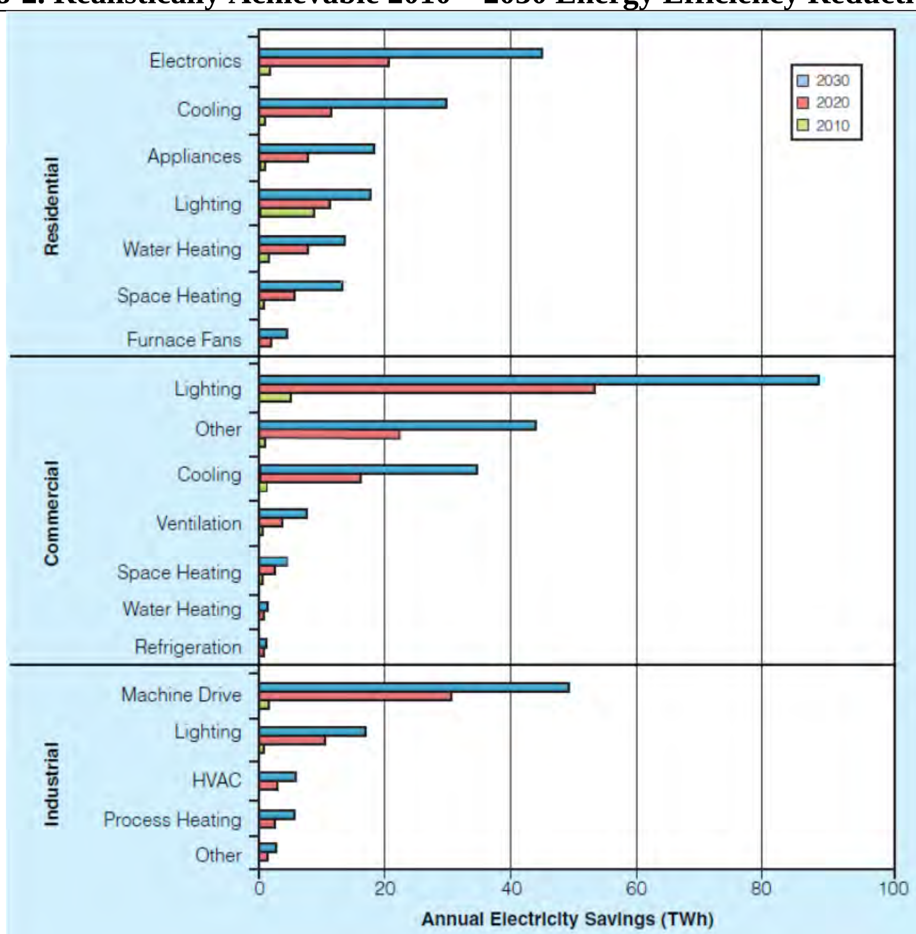
A current trend in these commercial and industrial chiller cooling systems is converting all devices to variable speed operation and a simplified control system. The initial conversions to this ultra-efficient operating format resulted in an average energy-use reduction of 54 percent over a three-year period.[265] The results indicate that ultra-efficient all-variable-speed systems are reliable and can be installed for the same cost as standard central plant chiller systems.

An example of effective application of all-variable-speed operation to an existing chiller plant is the County of San Diego's North County Regional Center, with 610,000 square feet of air-conditioned space, including a courthouse, offices, and a jail. The retrofit was completed and commissioned in 2003 at a cost of $423,700. Two years later, the entire plant was averaging less than 0.5 kW/ ton, saving the county more than $175,000 a year. The simple payback for this upgrade was less than two-and-a-half years.[266]

8.2.5 PG&E Energy Efficiency Rebate Programs

The Electric Power Research Institute (EPRI) prepared an estimate in 2009 of what it determined to be realistically achievable energy efficiency reductions in the 2010 - 2030 timeframe for the U.S. as whole. EPRI identified about 400,000 to 500,000 GWh of energy efficiency reduction potential in the residential, commercial, and industrial sectors, as shown in Figure 8-2.[267]

Figure 8-2. Realistically Achievable 2010 – 2030 Energy Efficiency Reductions, U.S.



Achieving all cost-effective energy efficiency measures will not happen over the next decade if PG&E and other utilities continue to rely on piecemeal energy efficiency rebate programs to deliver energy efficiency gains. PG&E provides modest rebates across a wide range of appliances, including (but not limited to) lighting, dishwashers, clothes washers, hot water heaters, and room air conditioners. For example, the rebate on a hot water heater ranges from $30 to $50.[268] PG&E offers no rebates for the biggest contributor to summertime peak load demand – central air conditioners.[269]

The process of applying for a PG&E energy efficiency rebate is not trivial. The relative complexity of the process, combined with the relatively low value of individual rebates, limits the effectiveness of the PG&E rebate program in motivating consumers to select high efficiency devices. The PG&E rebates page - How to Apply for eRebates - explains the process.[270] The rebate steps are shown in Table 8-1.

The state's *Energy Efficiency Strategic Plan* notes the weakness of this approach to energy efficiency and outlines the solution:[271]

> The IOUs currently offer a wide range of energy efficiency programs for existing homes, including audits, efficient appliance rebates, and consumer education. This Plan envisions a refocusing of these programs to move from a widget-based approach to a whole house approach to program delivery to offer comprehensive packages of audits, demand side management options and tools, rebates and financing options, and installation services.

Table 8-1. Steps to Receive Energy Efficiency Rebate through PG&E eRebates Program

You'll need to login to My Account to use eRebates.

1. Login to My Account. From the left navigation bar, click "Energy Tips & Rebates"
2. Click "Rebates"
3. Click "Apply Online"
4. Begin the eRebates Application Process
5. Print the eRebates Confirmation Page (you will need access to a printer)
6. FAX or mail the eRebates Confirmation Page and all proofs of purchase to PG&E

One off-the-shelf solution that could have a substantial near-term impact would be for PG&E to use rebate funds to cover the difference between the cost of minimum federal standard central air conditioning units and state-of-the-art central air conditioning units. This would result in maximum energy efficiency reduction every time a new central air conditioning unit is purchased.

Carrier Corporation is a leading provider of central air conditioning systems. The energy demand of a 3-ton Carrier Corporation SEER 10 central air conditioning unit is approximately 4.0 kWh under hot summertime conditions.[272] The company advertises a 56 percent reduction in electricity demand for its Infinity® 21 (SEER 21) model compared to a SEER 10 unit.[273] In parts of the Bay Area where air conditioning is used through the summer, in the range of 800 to 1,000 hours per year, as much as 2,000 kWh of energy demand would be eliminated over the course of the summer peak season by selecting the Infinity® 21for the upgrade.[274]

The 2006 federal standard for new central air conditioning units is SEER 13. The difference in the installed cost prior to rebates of a reference case Carrier Corporation 3-ton SEER 13 residential central air and heating unit, which costs approximately $9,000, and a state-of-the-art Infinity® 21 unit (SEER 21) is around $2,000.[275] Carrier offers a rebate on high efficiency units that reduces the cost difference between the SEER 13 and SEER 21 alternatives by about $1,000.

The duration of the summer on-peak period in PG&E service territory is about 768 hours.[276] The SEER 21 unit would save approximately 900 kWh relative to the SEER 13 unit over 768 hours.[277] Summer peak savings would be $270 per year, assuming a Tier 3 residential rate of $0.30/kWh.[278] The simple payback for the $2,000 additional cost of the Infinity® 21, without the Carrier rebate, would be 8 years. With the $1,000 rebate, the simple payback would be 4 years.

In addition, the typical reduction of about 2 kW in residential electricity demand when upgrading from an existing 3-ton central air conditioning unit to a SEER 21 unit would eliminate $600 per year in peaking gas turbine fixed costs. This is the cost associated with new peaking gas turbine capacity, like 760 MW Marsh Landing or 200 MW Mariposa Energy Center, that would otherwise be built to meet the peaking load.[279]

At a minimum, the value of upgrading to a highly efficient 3-ton central air conditioning unit ranges from $600 to $870 per year. This includes the avoided cost of new peaking gas turbine capacity that would otherwise be built to meet the demand, and the value of high-cost electricity that is not needed because of the high efficiency of the unit.

Implementing a cost-effective, state-of-the-art requirement for residential central cooling system upgrades would be simple in concept. For example, PG&E would advise local heating and cooling system contractors that utility rebate funds will pay the difference between the base price for a central air conditioning system that meets the 2006 federal SEER 13 standard and a state-of-the-art SEER 21 unit. PG&E, or a third party service provider, would identify each municipality and area in the Bay Area where the upgrade is a priority, such as inland areas of Marin, Sonoma, Napa, Solano, Contra Costa, Alameda, and Santa Clara counties. Bay Area climate zones are shown in Figure 8-3.

The incentive payment would also be available in cooler areas where air conditioning systems are run only on the very hottest days, such as communities located around San Francisco Bay, as it is more cost and climate efficient to pay the increment between SEER 13 and SEER 21 than to pay for additional peaking gas turbine capacity.

Figure 8-3. Bay Area Climate Zones Map[280]

PG&E has a central air conditioning cycling program intended to reach 25 percent of the 1.6 million PG&E customers with central air conditioning units.[281] The 25 percent participation target is based on the expected result of an aggressive marketing campaign. Cycling the set-point of one-half of the central air conditioner population from 72 °F to 78 °F for 10 or 15 minutes, and repeating this cycling with the other half of the population for 10 to 15 minutes, reduces the instantaneous MW load during critical peak demand periods by hundreds of MW with almost no impact on the comfort of end users.

Residences with sensitive populations, such as the elderly or chronically sick, would be kept out of this type of program. Other customers could opt-out if a reason was provided after the customer had been included in the program for a time and had experienced the effect, or lack of effect, of air conditioning cycling on the comfort level within the residence.

Central air conditioning units have an average service life of 10 to 14 years.[282] At least 50 percent of current central air conditioning units will be replaced over the next 10 years. If each replacement on average reduces unit electricity consumption by 50 percent, the electricity consumption of the entire population of central air conditioning units will drop about 25 percent over the next decade.

Integrating air conditioning cycling capability into each new state-of-the-art central air conditioning unit sold would ensure near universal capability to participate in the air conditioner cycling program. Air conditioner cycling capability would be incorporated into each new unit prior to sale. This capability would reduce the instantaneous electricity demand from this population of air conditioners by 50 percent, as half these units would be offline at any given time while the other half are operational.

California's *Energy Efficiency Strategic Plan* calls for a 50 percent reduction in air conditioning loads by 2020. The 3-ton central air conditioning unit example shows that a 50 percent demand reduction can be achieved cost-effectively over time as existing units wear out and are replaced with off-the-shelf high efficiency alternatives. Shifting rebate funds to the air conditioning unit wholesale distribution level would assure that every new central air conditioning unit sold incorporates maximum energy efficiency.

8.3 PG&E Energy Efficiency Programs

The CPUC establishes targets for the IOUs to assure that they make adequate progress in achieving energy efficiency reductions in the ratepayer-financed energy efficiency and demand response programs the IOUs administer. A system of energy efficiency bonuses and penalties was established by the CPUC in September 2007.[283] The CPUC set the energy savings earnings levels using the hierarchy shown in Table 8-2:[284]

Table 8-2. Hierarchy of Energy Savings Targets and Associated Financial Returns

Level of energy savings	Return on net benefit (%)
Achievement > 100 percent of energy savings targets in all energy categories	12
Minimum of 85 percent of energy savings targets achieved	9
Achievement of energy savings targets between 65 and 85 percent	none
Achievement of energy savings targets below 65 percent	penalties assessed

In order to persuade the IOUs to promote energy efficiency programs to consumers, the CPUC set up a bonus mechanism designed to reward utility shareholders for efficiency gains and penalize them for failure to meet energy efficiency goals. A comprehensive CPUC staff report released in April 2010 found that from 2006 to 2008, PG&E did not make enough progress to trigger bonus payments.[285] According to the report, the utility fell into the penalty zone for both peak demand savings, 60 percent, and natural gas savings, 63 percent, and into the deadband for energy savings, 71 percent.[286]

The CPUC designed shareholder bonuses as a means to put energy efficiency on an equal footing with IOU investment in natural gas-fired procurement. The concept is to persuade the IOUs to invest in energy efficiency instead of building new natural gas-fired power plants. The IOUs have failed to develop energy efficiency programs that produce long-term energy savings that would offset the need to build more conventional power plants.

The CPUC's Division of Ratepayer Advocates (DRA) is challenging the award of bonuses to the PG&E, SCE, and SDG&E for poor performance on energy efficiency targets. DRA states:[287]

> In addition to the hundreds of millions of dollars in unearned bonuses, the utilities receive billions of dollars to run energy efficiency programs," DRA acting director Como said. "Yet the utilities' energy procurement policies don't demonstrate that these expensive energy efficiency programs actually offset the need to invest in new power plants. If the utilities are allowed to continue on this path ratepayers will likely end up both paying billions for mediocre energy efficiency programs and building more power plants. . . DRA believes California's experiment with a shareholder bonus program to produce energy efficiency gains is fundamentally broken.

8.4 Independent Administration of Energy Efficiency Funds

Energy Trust of Oregon (Energy Trust) is an independent nonprofit organization dedicated to assisting Oregon IOU ratepayers invest in energy efficiency and renewable energy. Created in response to Oregon legislation and overseen by the Oregon Public Utility Commission (OPUC), Energy Trust began operation in 2002.[288] Energy Trust became the principal administrator of energy efficiency and renewable energy programs for the benefit of ratepayers of Oregon's two largest electric IOUs.[289] Separate agreements with gas utilities address natural gas efficiency programs. Energy Trust has assisted customers of Portland General Electric, Pacific Power, Northwest Natural and Cascade Natural Gas save nearly $600 million in energy costs.[290]

Oregon legislation required the IOUs to collect 3 percent of their electric rates for investments in energy conservation and renewable energy in 1999. OPUC was authorized to direct most of these public goods funds to an independent, non-government entity. Because economic pressures had discouraged Oregon IOUs from investing in energy efficiency during the 1990s, the OPUC determined the 3 percent ratepayer charge should be managed by an entity devoted exclusively to ratepayer interests in energy conservation and renewable energy.[291]

The Oregon Legislature extended the life of Energy Trust's chief funding mechanism, a public goods charge paid by IOU customers, in 2007. Previously set to sunset in 2012, the fund was extended to 2026. At the same time, Oregon IOUs were authorized to collect supplemental funds for certain electric energy efficiency programs.

Oregon has similar GHG goals as California. The state must begin to reduce GHG emissions in 2010 and achieve GHG levels 10 percent less than 1990 levels by 2020. The long-range goal is to achieve GHG levels 75 percent below 1990 levels by 2050.[292] An independent, non-profit energy efficiency funds administrator is a critical element in Oregon's strategy for achieving GHG reduction targets.

Community Choice Aggregators (CCAs) in California are eligible to administer the public goods charges paid by their customers as a result of the SB 790 CCA legislation approved in 2011.[293] If a city or county forms a CCA, the CCA can administer the public goods funds collected from CCA customers.

8.5 Property Assessed Clean Energy - PACE

The PACE model was developed by the City of Berkeley in 2007.[294] Under the PACE model, no upfront investment is necessary to finance energy efficiency improvements and rooftop PV. The investment is repaid as property assessments semi-annually with property tax payments over 10 to 20 years. In the event of a transfer of ownership, remaining payments would be made by the new owner because the assessment is tied to the property. This financing approach alleviates concerns about upfront costs and return on investment.

California PACE legislation, AB 811, was passed into law in 2008. Sixteen states had PACE-enabling legislation in place by March 2010.[295] San Francisco launched a $150 million program in March 2010 and Los Angeles was preparing to unveil its own program. The Obama Administration supported PACE with $150 million in American Recovery and Reinvestment Act (ARRA) funding.[296]

The Federal Housing and Finance Agency (FHFA), regulator of federal housing corporations Fannie Mae and Freddie Mac, instructed these entities in July 2010 not to purchase mortgages on properties with PACE assessments.[297] The FHFA objected to PACE because in its view PACE assessments were not simple assessments associated with the property – the intent of the PACE concept – but financial obligations senior to mortgages, meaning they must be repaid first if a borrower defaults.

The FHFA action suspended development of PACE programs, especially residential PACE, in most parts of California and across the country. Sonoma County is the only region in the state that continued financing for energy efficiency and renewable energy retrofits through a PACE program despite the FHFA opinion. Sonoma County avoided the federal action principally because the loans are funded by the county treasury and not private lenders.[298]

Lawsuits have resulted in a formal comment procedure at the FHFA that may lead to resolution of this controversy.[299] Federal legislation has also been proposed to resolve the issue. Commercial buildings and homes with no mortgage, which account for about one-third of residential housing stock,[300] are unaffected by the FHFA position on PACE assessments.

The Sonoma County PACE program is known as the *Sonoma County Energy Independence Program*.[301] It has continuously operated successful residential and commercial PACE programs since 2009. The Sonoma County program is the model for the privately-financed, $100 million commercial PACE program launched in Sacramento in September 2011.[302] San Francisco launched its commercial PACE program, *GreenFinanceSF-Commercial*, in October 2011.[303]

PACE programs offer a financially manageable mechanism for homeowners and business owners to achieve ZNE in existing residential and commercial buildings. PACE is independent of utility-funded energy efficiency programs.

PG&E does offer a limited on-bill financing program for commercial customers and government agencies that is similar to the PACE program in some respects.[304] The program does not include rooftop PV.[305] On-bill repayment is now being studied by the CPUC as a potential replacement for the existing on-bill financing program.[306] On-bill repayment supplants limited ratepayer funding for on-bill finance with the larger source of private capital. Under the on-bill financing format, PG&E customers access loans from third party lenders to make energy efficiency improvements and then customers repay the loans via a line item on their utility bills.

8.6 Conclusions and Recommendations

- The central element of California's *Energy Efficiency Strategic Plan* is ZNE buildings.
- Off-the-shelf, cost-effective measures are available to substantially reduce electricity consumption in existing homes and businesses. These measures include: adding insulation to the interior of the existing walls; adding a film to the existing single glazed windows or replacing with double-pane windows; use of a variety of high efficiency lighting alternatives; use of high efficiency appliances, use of occupancy sensors; and use of a high efficiency heating, ventilating, and air conditioning system.

- Central air conditioning units have an average age of 10 to 14 years. At least 50 percent of current central air conditioning units will be due for replacement over the next 10 years. Assuming each replacement on average reduces unit electricity consumption by 50 percent, the electricity consumption of the entire population of central air conditioning units will drop about 25 percent over the next decade.

- Integrating air conditioning cycling capability into each existing and new state-of-the-art central air conditioning unit sold would ensure near universal capability to participate in the air conditioner cycling program.

- Adding cycling capability to all existing and new central air conditioning units would reduce the instantaneous electricity demand from this population of air conditioners by 50 percent, as half these units would be offline at any given time while the other half are operational.

- PG&E should not be administering public goods funds for energy efficiency measures. An independent non-profit organization, similar to the Energy Trust of Oregon, should be established to administer these public goods funds. If a city or county forms a CCA, the CCA should administer the public goods funds collected from CCA customers.

- PACE retrofit programs are an effective non-utility alternative to achieve the energy efficiency and rooftop PV targets.

9. Demand Response - Reducing Peak Demand

9.1 Potential of Demand Response

The demand for electricity is highly concentrated in the top one percent of hours of the year. In most parts of the United States, these 80 to 100 hours account for roughly 8 to 12 percent of the maximum or peak demand. In California in 2010, the top 100 hours accounted for about 14 percent of peak demand.[307]

California's three IOUs tested a variety of dynamic pricing designs in a $20 million pilot project that involved approximately 2,500 residential, small commercial, and industrial customers over a three-year period. The dynamic pricing rate structure hinges on the smart meter, which most PG&E customers now have. PG&E customers have raised concerns about high electricity bills and perceived meter and billing inaccuracies from PG&E's deployment of new meters.[308]

The IOU pilot project provided time-varying prices and smart meters to all participants. In addition, some of the participants also received enabling technologies such as smart thermostats and always-on gateway systems. Smart thermostats automatically raise the temperature setting on the thermostat by 2 or 4 degrees when the price becomes critical. Always-on gateway systems adjust the usage of multiple appliances in a similar fashion.

The experiment showed that the average IOU customer reduced demand during the top 60 summer hours by 13 percent in response to dynamic pricing signals that were 5 times higher than their standard tariff. Customers who had a smart thermostat reduced their load about twice as much, by 27 percent. Those who had the gateway system reduced their load by 43 percent.

The gateway smart meter system represents the maximum technical potential for demand reduction in the residential customer class. The smart meter system has the potential for lowering peak demand by 43 percent. In the commercial and industrial classes, automatic demand response programs that control multiple end-use loads while working with the energy management system that is installed in most facilities are projected to reduce demand by 13 percent.

The weighted average technical demand response potential for all classes is estimated at approximately 23 percent. The smart meter system, at a minimum, has the potential to facilitate a substantial reduction in electricity usage.

9.2 PG&E Demand Response Programs

PG&E has numerous programs to reduce usage at times of peak demand.[309] These are known as demand response programs. The PG&E demand response program consists of three separate elements: 1) demand response from existing programs, 2) an air conditioning cycling program, and 3), additional demand reduction from Critical Peak Pricing (CPP). The application of CPP to small business and residential customers is possible with the introduction of smart meters.

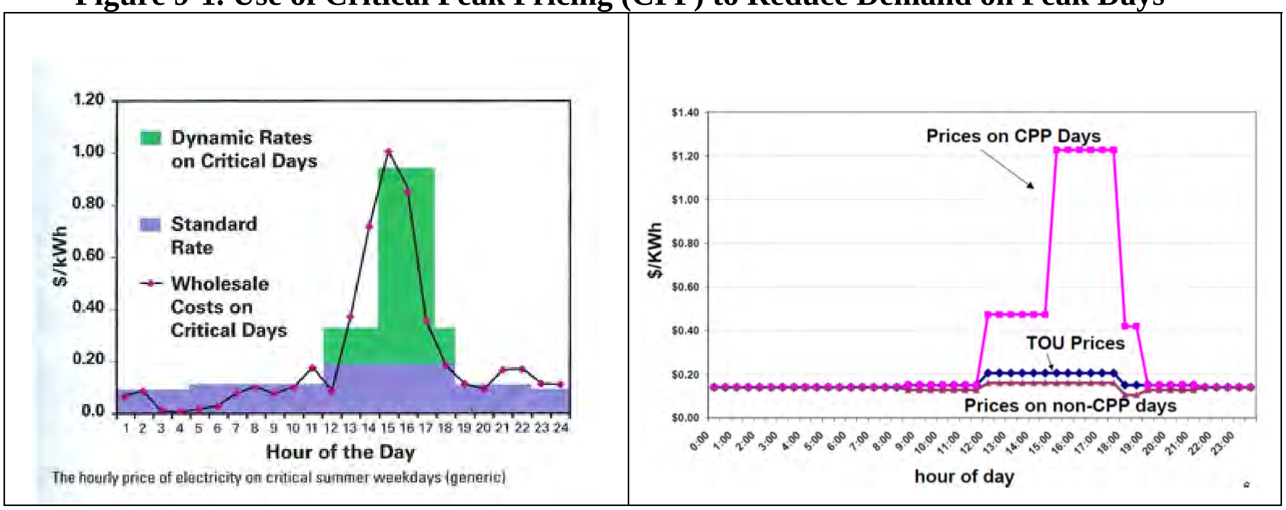
Collectively, the objective of these demand response programs is to reduce peak demand in PG&E service territory by approximately 5 percent by 2016.[310]

PG&E estimates that approximately 1.6 million of its residential customers are equipped with central air conditioning. Mature utility air conditioning cycling programs in other jurisdictions have achieved market penetration of up to 25 percent. This level of participation would result in approximately 300 MW of load reduction from an air conditioning cycling program in PG&E territory.[311]

PG&E has long-running non-firm electricity supply programs that have been effective in reducing peak load at participating sites. In the initial non-firm program begun in 1997, participants were given a rate discount in exchange for dropping their loads to a pre-determined level when given 30 minutes of notice by PG&E. Participants who did not comply with the curtailment order were penalized via a large energy charge on any power used in excess of their contracted amount. The program achieved a high compliance rate. The original non-firm program was phased-out several years ago and replaced with a revised program with a similar objective.[312]

One tool used by PG&E to reduce load on the very hottest peak days is to charge very high prices for electricity. The intent is to encourage customers to find ways to minimize usage during these periods to avoid high payments. This CPP pricing strategy is shown graphically in Figure 9-1.

Figure 9-1. Use of Critical Peak Pricing (CPP) to Reduce Demand on Peak Days[313,314]



The CPP rates are designed to provide incentives and penalties in the form of higher electricity costs to get non-residential customers to adjust their electric power usage schedules and become more energy efficient. The new CPP rates apply to all of PG&E's non-residential customers, including nearly 500,000 small-business customers. There are expected to be 9 to 15 days per year when prices will be especially high.[315] The price charged to the customer during CPP events is $1,200/MWh ($1.20/kWh).[316]

Optional peak day pricing rates that include time-of-use (TOU) rates during non-peak day pricing periods are available for residential customers with smart meters, but are not required. Residential customers can opt to return to standard residential tiered rates if they choose to do so.

PG&E bills residential customers using tiered rates. Customers using large amounts of electricity pay a considerable premium in this rate system. Tier 1 and 2 rates are billed at $0.13 to 0.15/kWh, and cover up to the baseline and from 101 to 130 percent of baseline, respectively.[317]. Tier 3 is billed at $0.30/kWh and covers usage from 131 percent to 200 percent. Tiers 4 and 5 are both billed at $0.34/kWh, and cover 201 to 300 percent and greater than 300 percent of baseline, respectively.[318]

About a third of the 31,000 GWh per year of PG&E residential usage is billed at the Tier 3 or higher rate.[319] One-third of 31,000 GWh is about 10,000 GWh per year. To put this quantity of electricity in perspective, over 5,000 MW_{ac} of distributed PV capacity would be required to generate 10,000 GWh per year.[320]

9.3 Conclusions and Recommendations

- Smart meters combined with automatic controllers have the potential to reduce residential peak demand by about 20 to 40 percent.
- Air conditioner cycling is an important tool for reducing peak demand.
- CPP is an effective method for shifting commercial peak loads from on-peak hours on the highest demand days.
- Air conditioner cycling should be maximized by integrating this capability into new air conditioners as a standard feature.
- Residential customers with significant consumption at the Tier 3 or higher rate are excellent candidates for demand response incentive programs.

10. BASE 2020 – The Plan

BASE 2020 is in its essence a combination of existing California state plans and policy. The *Energy Action Plan* loading order is a core element of BASE 2020. The *Energy Action Plan* prioritizes energy efficiency, rooftop PV, demand response, and combined heat and power (CHP) over conventional gas-fired generation to meet California's electricity needs. The *Energy Action Plan* is a strategic guideline document. However the *Energy Action Plan* priority list, or loading order, was established as a regulatory requirement by the CPUC in January 2012.[321]

The California *Energy Efficiency Strategic Plan* sets ambitious energy efficiency, rooftop PV, and air conditioning peak load reduction targets for the state.[322] A primary focus of the *Energy Efficiency Strategic Plan* is zero net energy (ZNE) buildings. The *Energy Efficiency Strategic Plan* energy efficiency and rooftop PV goals are the basis for the 2020 targets in BASE 2020.

Achievement of the BASE 2020 energy efficiency targets will reduce electricity usage from residential, commercial, industrial, and agricultural categories by approximately 25 to 30 percent in 2020 relative to the baseline year of 2008. Approximately 3,600 MW_{ac} of local PV will be added to achieve the ZNE targets for existing Bay Area homes and businesses. All new residential and commercial construction will be ZNE beginning in 2015.

The BASE 2020 CHP target of 840 MW for the Bay Area is derived from the *AB 32 Scoping Plan*, which calls for 4,000 MW of new CHP in California by 2020.[323] California has a large potential for biogas and biomethane production, principally from landfills and dairies. Extensive use of these biofuels in new CHP plants will minimize GHG emissions from these plants.

There are two existing large-scale renewable energy development zones in the Bay Area where expansion is underway or could be achieved with technology upgrades. Approximately 300 MW of new wind development is underway in the Montezuma Hills area of Solano County. This wind capacity is included in BASE 2020 in light of the high probability that it will be built. The modification of the existing conventional wet cooling towers at the geothermal plants in The Geysers region of Sonoma County to parallel wet-dry cooling systems could substantially increase output. BASE 2020 includes upgrading of cooling systems at The Geysers to increase output up to 300 MW and improve the sustainability of the geothermal resource.

400 MW of sodium-sulfide (or equivalent) battery storage will be integrated into the Solano County wind production area to provide 400 MW of peaking power and to smooth output from the wind generators. 200 MW of community-level battery storage will also be added to residential and commercial Bay Area districts to store mid-day PV output, provide peaking capacity, address the intermittency of solar electricity production, and serve as the foundation of community-scale microgrids that can operate around-the-clock on electricity supplied by rooftop PV.

Finally, the Bay Area already has extensive conventional natural gas-fired resources and one large dedicated hydroelectric resource (Hetch Hetchy). Additional generation sources in PG&E territory that supply the Bay Area include nuclear, natural gas-fired, large hydroelectric, coal and biomass. These resources, with the exception of the coal power, will provide ample electric generation support as the Bay Area transitions to a higher percentage of local renewable power. An additional element of BASE 2020 is the substitution of Bay Area clean power for in-state coal electricity purchases by PG&E.

Actual peak reserve margins, without considering the additional capacity of four new gas turbine projects that have approved power purchase agreements with PG&E, are in the range of 30 to 40 percent. This translates into an actual PG&E electricity supply surplus of 3,000 to 5,000 MW beyond the reserves required by the CPUC to assure grid reliability under all foreseeable conditions.

Peak loads will drop steadily over the next decade as BASE 2020 is implemented. The PG&E reserve margin will grow rapidly without additions of new gas-fired generation as a result. This same pattern is evident, to a lesser degree, in the seven 2010 – 2020 demand scenarios developed by the CPUC for PG&E in the *2010 Long-Term Procurement Proceeding*.[324] PG&E peak demand drops at an average rate of about 100 MW per year in those scenarios.

There is no grid reliability or peak demand justification for building new conventional natural gas-fired generation to meet Bay Area electricity needs. The purpose of existing gas-fired generation will be to provide the electricity demand that cannot be met by energy efficiency, demand response, CHP, distributed PV, existing utility-scale renewable energy supplying PG&E and the Bay Area POUs, and utility-scale additions in Solano County (wind) and Sonoma County (geothermal).

10.1 BASE 2020 Framework – The Energy Efficiency Strategic Plan

The energy efficiency goals established in the California *Energy Efficiency Strategic Plan* serve as the basis for the GHG emission reduction targets in BASE 2020. A description of the *Energy Efficiency Strategic Plan* goals for 2020 is provided in Table 10-1, along with quantification of the energy efficiency and rooftop PV reductions these targets represent.[325] An important component of the *Energy Efficiency Strategic Plan*, which is also integral to BASE 2020, is a 50 percent reduction in electricity demand of heating, ventilation, and air conditioning (HVAC) systems by 2020. The HVAC electricity demand reduction reaches 75 percent in 2030.[326]

Table 10-1. California Energy Efficiency Strategic Plan Goals[327]

Category	2008 statewide demand[328] (GWh)	Targets	2020 reduction in demand (GWh)	2020 statewide demand if targets achieved (GWh)
Residential	91,493 Single family: 61,026	2020: 25 percent of existing homes have 70 percent decrease in purchased electricity from 2008 levels, 75 percent of existing homes have a 30 percent decrease in purchased energy from 2008 levels, and 100 percent of existing multi-family homes have a 40 percent decrease in purchased	36,597	54,896

	Multi-family: 30,467	energy from 2008 levels. 100 percent of new homes will be ZNE. [Approximately one-third of all households live in multi-family residences and two-thirds in single family homes.][329]		
Commercial	106,569	2030: 50 percent of existing commercial buildings will be retrofit to ZNE through energy efficiency and the addition of clean rooftop PV. 100 percent of new commercial buildings reach ZNE in 2030. [It is assumed that 20 percent of existing commercial buildings reach ZNE by 2020 based on Commission projections.]	21,314 (20 percent ZNE by 2020)	85,255
Industrial	44,142	2020: Energy intensity of industrial facilities will be reduced by 25 percent.	11,035	33,107
Agriculture	20,705	2020: Energy intensity of agricultural operations will be reduced by 15 percent.	3,106	17,599
Subtotal	262,909		72,052	190,857
Misc. loads[330]	~14,000		--	14,000
Total	~277,000		72,052	204,857
Net reduction in statewide utility-supplied consumption, 2008 to 2020:				~26 percent

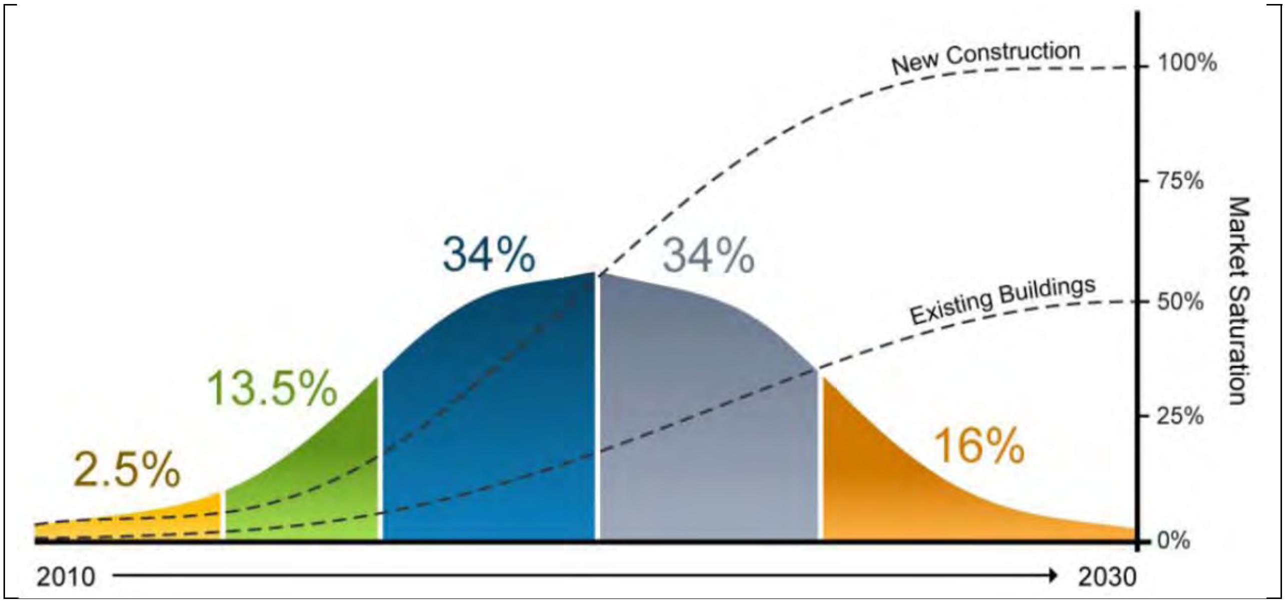
10.2 BASE 2020 Energy Efficiency and Distributed PV Targets

There are three substantive differences between the targets in the *Energy Efficiency Strategic Plan* and BASE 2020:

- The *Energy Efficiency Strategic Plan* assumes that 25 percent of existing residences achieve a 70 percent reduction in grid electricity usage by 2020. BASE 2020 assumes these residences achieve ZNE by 2020 through the addition of sufficient rooftop PV to achieve a net 100 percent reduction in grid electricity usage.
- The *Energy Efficiency Strategic Plan* assumes that 50 percent of existing commercial buildings achieve ZNE by 2030 with no interim 2020 target. The CPUC projects that nearly 20 percent of existing commercial buildings will reach ZNE by 2020, as shown in Figure 10-1. BASE 2020 sets a target of 25 percent of existing commercial buildings achieving ZNE by 2020. The *Energy Efficiency Strategic Plan* target of 50 percent of existing commercial buildings achieving ZNE by 2030 remains unchanged.

The *Energy Efficiency Strategic Plan* assumes that all new residential construction is ZNE by 2020 and all new commercial construction is ZNE by 2030. BASE 2020 assumes that all new residential and commercial construction is ZNE beginning in 2015.

Figure 10-1. Rate of Retrofit of Existing Commercial Buildings to ZNE from 2010 to 2030[331]



BASE 2020 uses the term "rooftop PV" more broadly than the *Energy Efficiency Strategic Plan* definition. The types of PV envisioned for the Bay Area in BASE 2020 include rooftop PV, parking lot PV, and ground-mounted PV up to 20 MW connected to the distribution grid. This broader definition of rooftop PV is more accurately described as distributed PV. However, the framework PV assumption in BASE 2020 is that the PV will be predominantly located on rooftops and parking lots.

The BASE 2020 energy efficiency and PV targets are shown in Table 10-2. The effect of applying these targets statewide is also calculated in Table 10-2.

Table 10-2. BASE 2020 Targets - Purchased Electricity Reductions from Energy Efficiency Measures and Distributed PV if Applied Statewide

Category/ demand (GWh)	Targets	Split between EE measures and PV to achieve 2020 target (GWh)
Residential, 91,493 Single family: 61,026 Multi-family: 30,467	Assume 75 percent of existing homes achieve 30 percent EE reduction target through EE measures alone. 25 percent of existing homes are converted to ZNE homes, with 30 percent of demand reduction from EE measures and 70 percent from PV. Existing multi-family homes achieve 30 percent EE reduction target through EE measures. The remaining 10 percent reduction necessary to achieve the overall 40 percent reduction goal is achieved with PV.	a. 25 percent of existing single family homes attain ZNE, a 15,267 GWh reduction: EE: 4,577 GWh PV: 10,680 GWh b. 75 percent of existing single family homes achieve 30 percent reduction via EE alone: EE: 13,731 GWh c. 100 percent of existing multi-family housing achieves a 40 percent

		reduction, 30 percent with EE and 10 percent with PV, a 12,187 GWh reduction: EE: 9,140 GWh PV: 3,047 GWh
Commercial, 106,569	25 percent of existing commercial buildings will retrofit to ZNE by 2020, with 30 percent of demand reduction from EE measures and 70 percent from PV. 75 percent of existing commercial buildings will reduce electricity consumption by 30 percent through energy efficiency measures, consistent with the residential target and previously established state energy efficiency goals for commercial buildings.[332] 50 percent of existing commercial buildings will be retrofit to ZNE through energy efficiency and rooftop PV by 2030, consistent with the *Energy Efficiency Strategic Plan*.	25 percent of existing commercial buildings attains ZNE, a total of 26,642 GWh: EE: 7,993 GWh PV: 18,650 GWh 75 percent of existing commercial buildings reduce consumption 30 percent, a total of 23,978 GWh: EE: 23,978 GWh
Industrial, 44,142	2020: Energy intensity of industrial facilities will be reduced at least 25 percent.	100 percent of industrial facilities achieve 25 percent reduction via EE alone: EE: 11,035 GWh
Agricultural, 20,705	2020: Energy intensity of agricultural operations will be reduced at least 15 percent.	100 percent of agricultural operations achieve 15 percent reduction via EE alone: EE: 3,106 GWh
Statewide energy efficiency and PV reductions:		EE: 73,560 GWh PV: 32,377 GWh
Net reduction in statewide utility-supplied consumption, 2008 to 2020:		~38 percent

The purchased electricity reductions that would be achieved in PG&E's planning area and the Bay Area if BASE 2020 energy efficiency and rooftop PV goals are met are provided in Table 10-3. These reductions are a subset of the statewide reductions shown in Table 10-2.

Table 10-4 converts the GWh of purchased electricity reductions attributable to PV to MW_{ac} capacity, assuming an average annual output for fixed PV in the Bay Area of approximately 1,900 kWh per kW_{ac} of installed capacity.[333]

Table 10-3. Allocation of Statewide PV and Energy Efficiency Reductions in PG&E Planning Area and Bay Area[334,335]

2020 statewide reduction (GWh)	2020 PG&E planning area		2020 Bay Area	
	% of statewide reduction	allocation (GWh)	% of statewide reduction	allocation (GWh)
EE: 73,560 PV: 32,377	38	EE: 27,953 PV: 12,303	21	EE: 15,448 PV: 6,799

Table 10-4. Conversion of PV Energy Production (GWh) to PV Capacity (MW)

2020 statewide		2020 PG&E planning area		2020 Bay Area	
GWh	MW_{ac}	GWh	MW_{ac}	GWh	MW_{ac}
32,376	17,040	12,303	6,475	6,799	3,578

Nearly 3,600 MW_{ac} of distributed PV must be added in the Bay Area by 2020 to achieve the BASE 2020 PV target. By 2020, over 17,000 MW_{ac} of distributed PV would be necessary in California if BASE 2020 targets were applied throughout the state.

10.3 GHG Reductions Achieved by BASE 2020

Table 10-5 summarizes the actions to be taken in BASE 2020 to reduce GHG emissions. BASE 2020 assumes that RPS renewable energy projects built to meet the 2013 RPS target of 20 percent, large hydro, and nuclear plants continue to operate at projected typical output levels in 2020, while output from natural gas plants is reduced and coal plant power is displaced entirely. Achieving BASE 2020 targets would reduce Bay Area GHG emissions from electricity usage more than 60 percent by 2020 relative to a 2008 baseline, from 19 million tons per year to 7 million tons per year. Peak load on the grid would be reduced more than 50 percent.

The 2008 PG&E peak load was 21,827 MW.[336] As noted, the nine Bay Area counties account for approximately 60 percent of PG&E service territory electricity usage. Therefore, the 2008 peak load attributable to PG&E Bay Area bundled and Direct Access customers is 0.60 × 21,827 MW = 13,096 MW. The CEC estimates a 2008 peak load attributable to Bay POUs of 899 MW.[337] The total nine-county Bay Area peak load in 2008, including PG&E peak loads and Bay Area POU peak loads, was approximately 14,000 MW.

Table 10-5. Bay Area CO_2 Reduction Achieved by Implementing BASE 2020

Source of CO_2 reduction	Quantity of reduction (GWh)	CO_2 emissions (10^6 tons)	Fuel type displaced	CO_2 emission factor of fuel type displaced (tons/MWh)	Avoided CO_2 emissions (10^6 tons)	Net CO_2 reduction (10^6 tons)
Energy efficiency	15,448	0	PG&E average	0.32	4.9	4.9
Rooftop PV	6,799	0	natural gas	0.50	3.4	3.4
CHP	6,770	1	imported power mix	0.48	3.2	2.2
New geothermal	2,234	0	imported power mix	0.48	1.1	1.1
New wind w/ energy storage	867	0	imported power mix	0.48	0.4	0.4
Total reduction/ displacement:						12.0

The Bay Area peak load reductions that would occur as a result of the implementation of BASE 2020 are shown in Table 10-6. Bay Area peak load would decline on the PG&E and Bay Area POU systems from the 2008 peak of approximately 14,000 MW to about 6,500 MW in 2020, a decline of more than 50 percent. The majority of the peak load decline would result from energy efficiency measures combined with substantially more efficient central air conditioner performance and management.[338] The remaining peak reduction would be demand shifted from PG&E to rooftop PV, CHP and community-level battery storage.

Table 10-6. Bay Area Peak Load Reduction Achieved by Implementing BASE 2020

Source of reduction	Basis of reduction (MW)	Peak load reduction (MW)
Energy efficiency[339]	25 percent reduction in demand on average from energy efficiency measures.	2,500
Air conditioner/ chiller plant efficiency improvement	Cooling load represents about 30 percent of peak load. Highest efficiency central air conditioning (CAC) units replace worn-out units, 50 percent reduction. Same reduction targeted for commercial building chiller plants. Cycling capability added to existing and new CAC units to allow 50 percent online, 50 percent offline at peak. A 50 percent turnover in CAC population in 10 years.	2,100
Rooftop PV	3,800 MW_{ac} of rooftop PV added over decade. 50 percent of this capability, 1,900 MW_{ac}, available at peak.	1,900
Battery storage associated with rooftop PV	200 megawatts of battery storage will also be added to residential and commercial Bay Area buildings to store mid-day PV output, provide peaking capacity, address the intermittency of solar electricity production, and serve as the foundation of community-scale microgrids that can operate around-the-clock on electricity supplied by rooftop PV.	200
CHP	840 MW of CHP is added to Bay Area, removing equivalent amount of load from utility demand at peak.	840
Total Bay Area peak load reduction:		7,540

An important administrative element of BASE 2020 is the phase-out of coal power purchases. As discussed in Chapter 3, PG&E relies on significant amounts of coal power embedded in wholesale market power purchases to meet demand. This is true even though natural gas prices are at low levels, are expected to stay at low levels for years to come, and California's large fleet of high efficiency natural gas-fired combined cycle plants are underutilized at an average capacity factor of 50 percent.[340]

Major combined cycle fleet owners are now competing in low price bulk power markets, competing against coal capacity.[341] There is no longer a compelling economic argument against displacing the coal component with natural gas in wholesale power market purchases. PG&E should issue a request for offers to energy service providers requesting they provide a wholesale market power product that: 1) does not include coal power, and 2) preferentially matches the composite GHG footprint of PG&E-owned and contracted generation.

The transition of PG&E coal QF contract suppliers from coal or coal-equivalent fuel to biomass, as in the case of Mt. Poso Cogeneration, is a positive step that should be continued to complete the phase-out of coal and coal-equivalent fuel in PG&E territory by no later than 2020.

10.4 Zero Net Energy Buildings Are Cost-Effective

In 2009 the CPUC evaluated a renewable energy strategy that relies primarily on distributed PV, known as the "High DG" strategy, to achieve the state's 33 percent by 2020 goal.[342] The High DG alternative substitutes 15,000 MW_{ac} of distributed PV for a comparable amount of remote utility-scale solar and wind projects in the 33 percent by 2020 reference case utility scenario.[343] The distributed PV target of 15,000 MW_{ac} by 2020 in the High DG scenario is comparable to the de facto 2020 rooftop PV goal in the *Energy Efficiency Strategic Plan* of 14,000 MW_{ac} and the BASE 2020 target, if applied statewide, of 17,000 MW_{ac}.

The CPUC determined that the cost of the High DG alternative would be comparable to the cost of the utility reference case scenario if the capital cost of PV was about one-half the $7/$W_{ac}$ capital cost assumed by the CPUC in its analysis. $306/MWh was the levelized cost-of-energy assumed for the $7/$W_{ac}$ distributed PV capital cost. The CPUC stated that a distributed PV capital cost of $3.70/$W_{ac}$ would result in cost parity with the utility 33 percent reference case scenario. The distributed PV levelized cost-of-energy assumed by the CPUC for distributed PV with a capital cost of $3.70/$W_{ac}$ was $168/MWh.[344]

The CPUC prepares quarterly summary reports on the state's progress toward RPS goals. The fourth quarter 2011 report includes pricing data on RPS contracts for the first time, in conformance with SB 836 (2011) RPS contract price reporting requirements.[345] SB 836 requires that average RPS contract prices be reported by contract year, technology type, and size range by each IOU. The average 2010 and 2011 contract prices reported by PG&E for solar PV, solar thermal, and wind are summarized in Table 10-7.

Table 10-7. Average PG&E 2010/2011 RPS Contract Prices: PV, Solar Thermal & Wind[346]

Technology	Size range (MW)	2010 contract price ($/MWh)	2011 contact price ($/MWh)
PV	0 - 3	130	129
	3 - 20	167	114
	20 - 50	139	none listed
Solar thermal	50 - 200	144	none listed
Wind	20 - 200	126	118

Note: No explanation is provided in the CPUC 4th quarter 2011 report regarding why the 2010 PG&E 3-to-20 MW PV contract prices were nearly 30 percent higher than the 2010 contract prices for 0-to-3 MW PV systems.

Competitive 2011 power purchase contract prices for commercial rooftop PV systems in California are: $130/MWh for 1 MW systems, $140/MWh for 500 kW systems, and $150/MWh for 100 kW systems.[347] This pricing is consistent with the PG&E 2010 and 2011 average RPS contract prices of about $130/MWh for 0 to 3 MW PV systems. It is also consistent with the City of Palo Alto Utilities clean energy FIT program. The 2012 tariff price for commercial rooftop PV systems that are 100 kW or greater is \$0.14/kWh, or \$140/MWh.[348,349] This clean payment rate for commercial rooftop PV systems is well below the parity price of \$168/MWh identified by the CPUC for the utility reference case 33 percent RPS compliance strategy.

The 2011 contract price data reported by PG&E indicates that smaller scale PV systems, either 0-to-3 MW at \$129/MWh or 3-to-20 MW at \$114/MWh, are substantially more cost-effective than 50-to-200 MW solar thermal at \$144/MWh. An unexpected data point in the PG&E contract price information is that the 2011 average contract price for PV across the 0-to-20 MW spectrum, at \$121/MWh, is essentially the same as the average PG&E 2011 wind power contract price at \$118/MWh.

The installed cost of small commercial 10 to 100 kW rooftop installations in Germany, where PV panel and balance-of-system hardware costs are comparable to those in the U.S., dropped to a gross capital cost of about \$2.70/W_{dc} on average in the third quarter of 2011.[350] See Figure 10-2. The cost-of-energy for a commercial PV system with a gross capital cost of \$2.70/W_{dc} would be less than \$100/MWh in the U.S. without state incentives.[351] The overwhelming majority of PV installations in Germany are rooftop installations, as shown in Figure 10-3.

The gross capital cost of German residential rooftop PV systems less than 10 kW is about \$3.00/W_{dc} on average in the third quarter of 2011, about 10 percent higher than the cost of small commercial rooftop PV systems in Germany, as shown in Figure 10-3.[352] Overall, prices for PV are forecast to continue drop by 15 percent per year until 2015 due to oversupply and cheaper production.[353]

Figure 10-2. 2011 Capital Cost of German Residential & Small Commercial PV Systems[354]

[\$1.31 = 1.00 €]

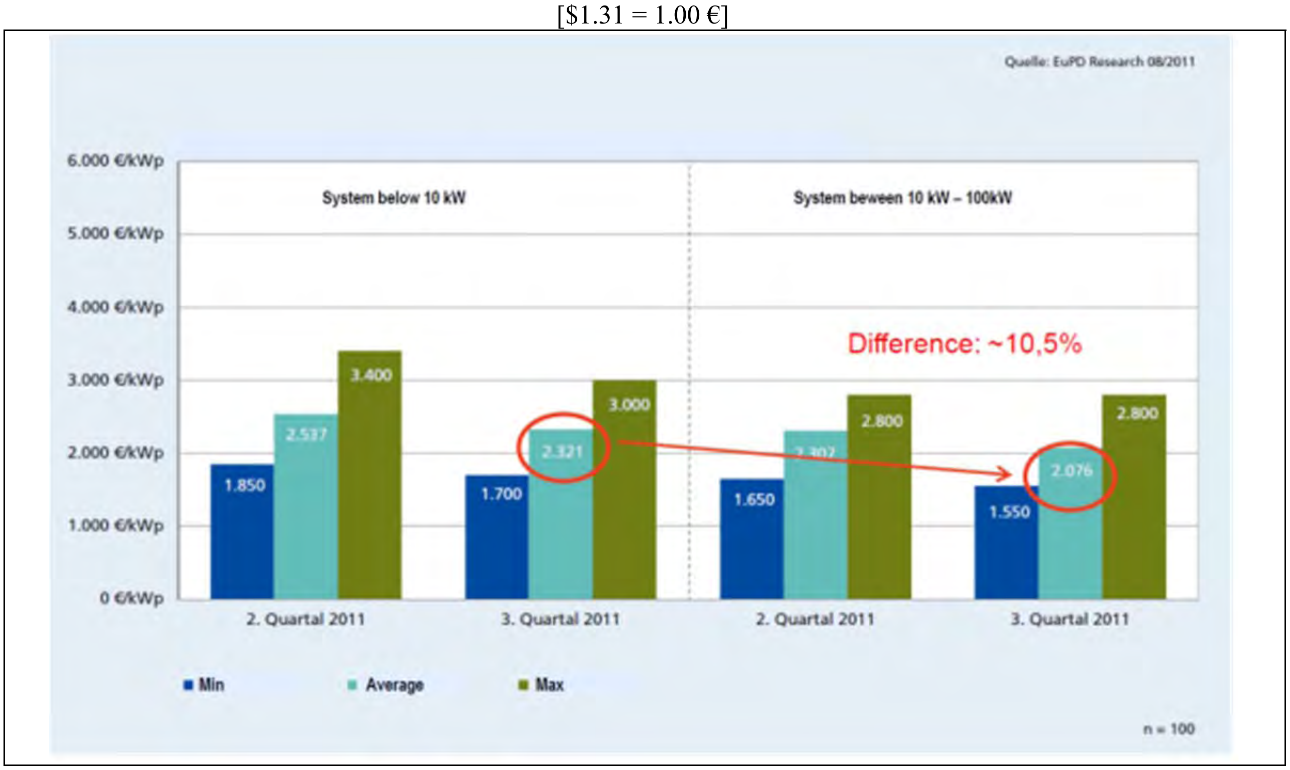
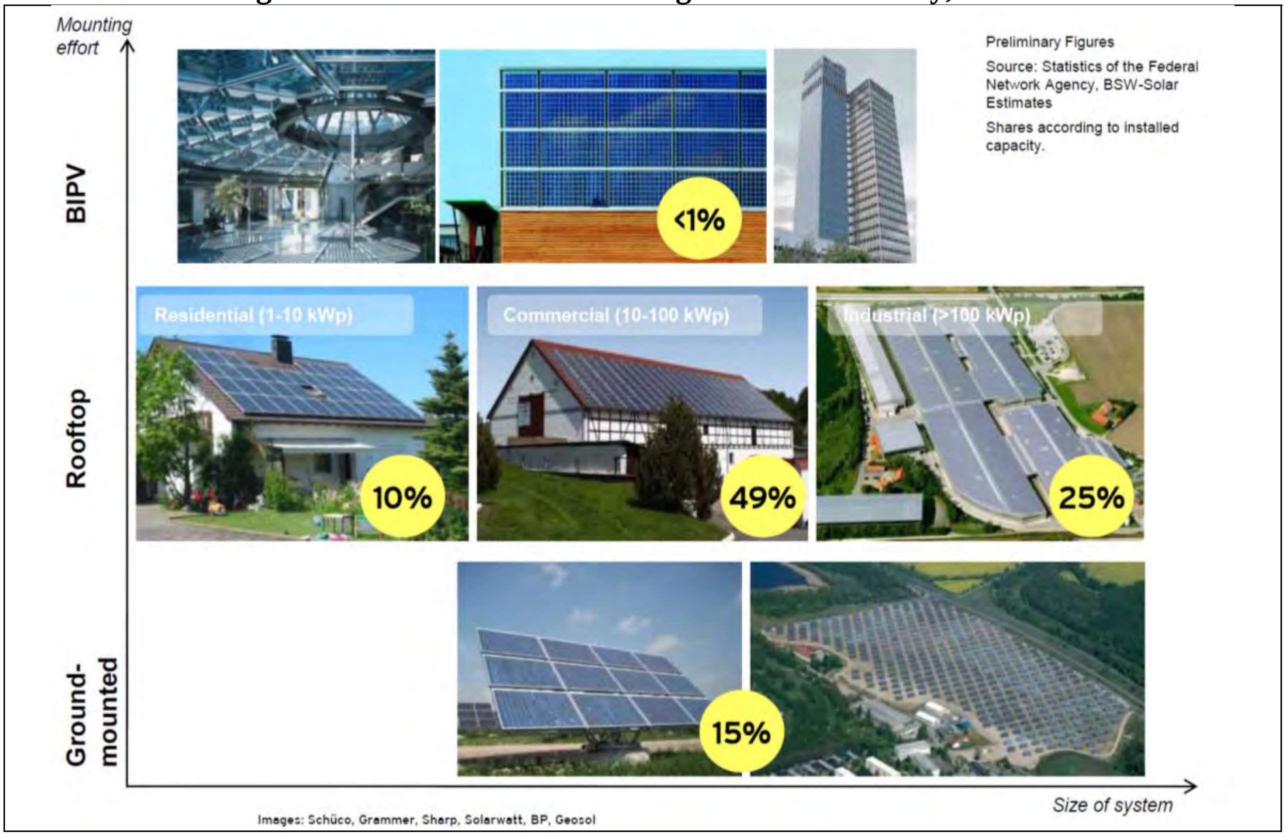


Figure 10-3. Solar PV Market Segments in Germany, 2010[355]



PV panels equipped with integrated micro-inverters that convert direct current electricity to alternating current at the panel are reducing cost and simplifying installation. The lowest published cost to date for residential PV systems in California, $4.40/$W_{dc}$, is being offered by the company Open Neighborhoods in Los Angeles for a 2 kW_{dc} system using micro-inverters.[356] This is equivalent to a cost-of-energy of about $0.20/kWh.[357] Use of micro-inverters is expanding rapidly in California. Solar panels equipped with micro-inverters accounted for 34.4 percent of residential installations and 16.5 percent of small commercial installations, based on total wattage, in 2011.[358]

A major economic advantage of rooftop PV, when it is owned by the homeowner or business owner, is the increased assessed value of the property as a result of the PV array. A 2011 study by Lawrence Berkeley National Laboratory indicates the assessed value of a California home with a PV array increases by nearly as much as the capital cost of PV system when it is installed.[359] The average resale premium for existing homes with PV was more than $6/$W_{dc}$.

10.5 Conclusions and Recommendations

- The California *Energy Efficiency Strategic Plan* goals for energy efficiency, rooftop PV, and air conditioner demand reduction, form the framework of BASE 2020.

- Real energy efficiency reductions of 25 to 30 percent are achievable.

- Combining air conditioner cycling with use of highest efficiency units makes achievable a 50 percent reduction in air conditioner loads.

- 25 percent of existing Bay Area homes and businesses must achieve ZNE by 2020 to meet BASE 2020 targets.

- Approximately 3,600 MW_{ac} of rooftop PV must be added in the Bay Area bv 2020 as an element of meeting the ZNE targets.

- Competitive 2011 power purchase contract prices for commercial rooftop PV systems in California were $130/MWh for 1 MW systems, $140/MWh for 500 kW systems, and $150/MWh for 100 kW systems.

- The City of Palo Alto Utilities 2012 clean payment rate of $140/MWh for commercial rooftop PV systems of 100 kW and above is well below the parity price of $168/MWh identified by the CPUC when it compared the cost-of-energy of the IOU reference case 33 percent RPS compliance strategy with a High DG alternative.

- Meeting ZNE and renewable energy targets with a primary focus on rooftop and local PV is cost-effective.

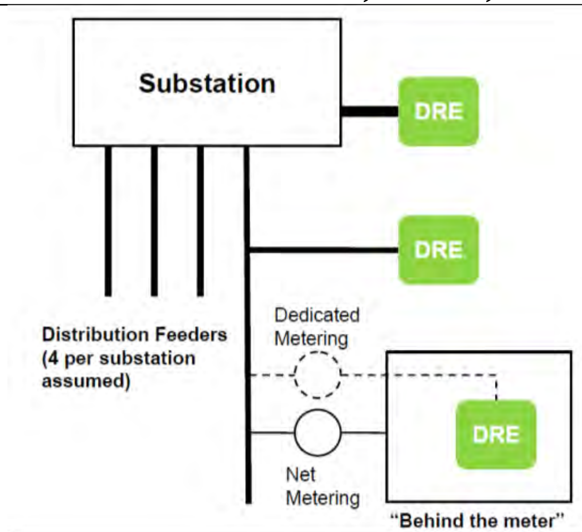
- The installation rate of PV systems can be incrementally accelerated to meet the growth rate of electrical vehicles.

- BASE 2020 will achieve GHG reductions of more than 60 percent compared to a 2008 baseline.

11. Integrating Distributed Generation (DG) Into the Grid

The T&D system has changed little over the last century. It is configured to transmit electricity generated at large power plants over high voltage transmission lines to distribution substations where the voltage is reduced. The electricity then flows from the distribution substations along feeders to customers. Safety devices, like circuit breakers located at distribution substations and reclosers on the feeders, are currently constructed assuming electricity will always flow in one direction. To accept high levels of DG, at some point these safety devices must be upgraded to allow two-way flow. The relationship between distribution substations, feeders, and DG sources is shown in Figure 11-1.[360]

Figure 11-1. Distribution Substation, Feeders, and DG Sources



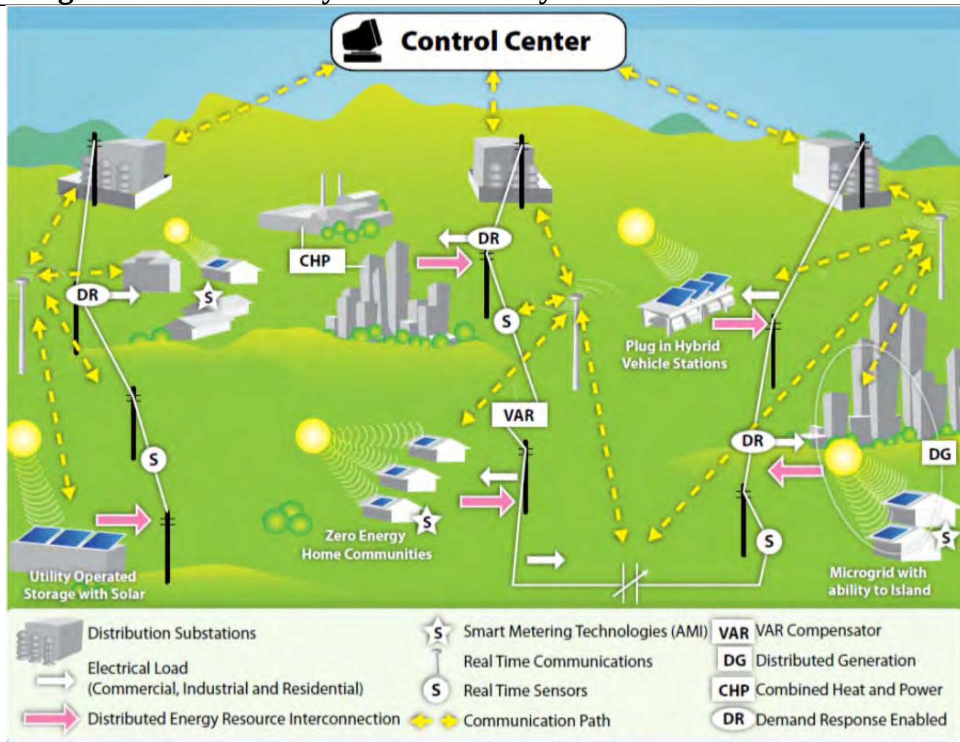
DRE = distributed renewable energy

The CEC made clear in 2007 that incorporating bidirectional capability into distribution substations and feeders is a commonsense need in a smart grid environment where higher-and-higher levels of DG are encouraged and expected, stating:[361]

- Utilities spend approximately three-fourths of their total capital budgets on distribution assets, with about two-thirds spent on upgrades/new infrastructure in most years.
- Investments will remain for 20 to 30 or more years.
- Magnitude of these investments suggests need to require utilities, before undertaking investments in non-advanced grid technologies, to demonstrate that alternative investments in advanced grid technologies that will support grid flexibility have been considered, including from a standpoint of cost-effectiveness.

The CEC's vision of a two-way distribution system that is optimized for high levels of DG is shown in Figure 11-2.

Figure 11-2. Two-Way Distribution System for DG Environment[362]



The CEC correctly identified a fully two-way distribution grid as a priority in 2007. There is no requirement that the IOUs assure full two-way flow capability in new or upgraded distribution substations as of March 2012. However, SB 17 (2009) establishes as state policy the modernization of the California's electrical grid. The objective of this smart grid policy is to maintain reliable and cost-effective electrical service while integrating high levels of distributed generation resources, demand-side resources, energy storage, and electric vehicles.[363]

Some European countries are well ahead of California in making their distribution grids compatible with high levels of DG. Netherlands is one example. The country has an average demand of about 14,000 MW.[364] Over a three-year period from 2004 through 2006, about 1,500 MW of 1 to 3 MW CHP plants were brought online in areas with a high density of greenhouses.[365] The country also has over 2,200 MW of installed wind capacity.[366]

The Netherlands has made a strategic commitment to the development of DG resources. The country is simulating where major DG development will occur and pro-actively planning necessary grid upgrades to avoid the grid becoming a bottleneck to DG development. This process is explained in the following paragraphs from a 2011 article published in the Proceedings of the Institute of Electrical and Electronics Engineers:[367]

> In The Netherlands local authorities have designated specific areas for the development of greenhouses. Each greenhouse may contain a CHP plant with a capacity in the range of 1 to 3 MVA (MW) and thus to be connected to the local medium voltage grid. Due to the high density of greenhouses in such areas, the penetration level of CHP plants in the medium-voltage grid is very high. This can amount to a total generated power of 100 MW or even more, and with loads far less than the generation power."

> The Dutch regulatory framework requires the distribution system operators to provide a connection to the distribution grid within 18 weeks upon a client's request. The capacity and structure of today's (Dutch) distribution grids in these areas does not support a connection of a large number of CHP plants. The time it takes to execute projects in the grid to secure reinforcements does not match the legal time it takes to make a grid connection for a new DG unit.
>
> To mitigate these planning issues, proactive grid planning by both the distribution system operator and the transmission system operator is necessary. To plan the grid in a proactive way, several transmission development scenarios have to be established. With the aid of these scenarios, bottlenecks in current medium voltage grids and sub-transmission grids can be identified. In each scenario, alternative grid designs have to be generated for each bottleneck. These alternatives are to be generated in such a way that the expected growth of CHP plants in each scenario is covered.

The methodical, pro-active upgrade approach being utilized by the Dutch to assure the distribution grid can absorb large amounts of DG in concentrated locations is also needed in California. However, even without such upgrades, large amounts of DG can flow onto the existing one-way system without causing safety devices to mistake DG power flows for ground faults. There is always some flow on the distribution circuits, and as long as the DG flow onto the circuit is less than the total demand on that circuit, the one-way flow will be maintained.

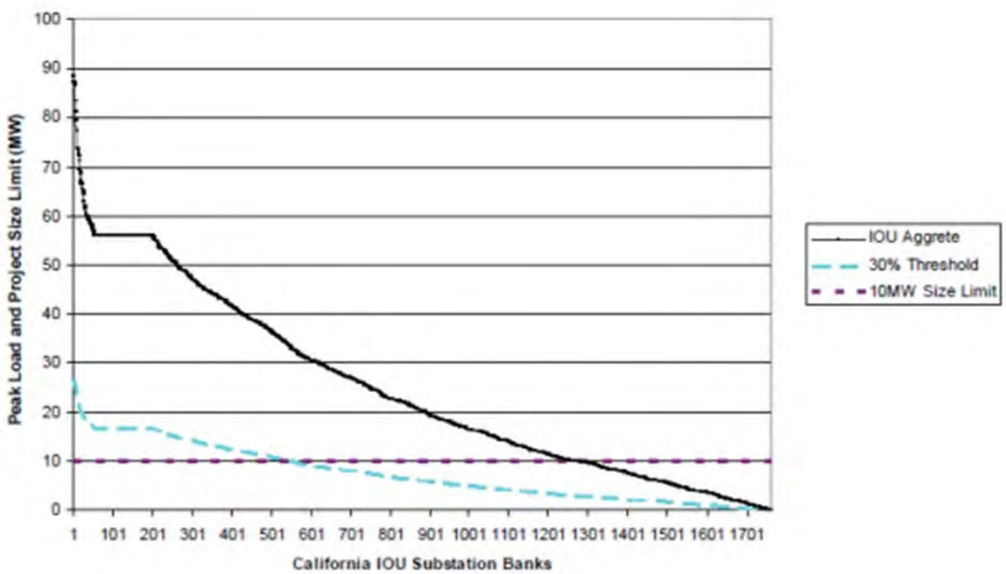
11.1 PV Capacity of Existing Distribution System

Rule 21 specifies standard interconnection, operating, and metering requirements for DG sources.[368] The CPUC has calculated in the context of Rule 21, for the entire inventory of approximately 1,700 existing IOU substations in California, the amount of distributed PV that could be accommodated with minimal interconnection cost. The CPUC states:[369]

> Rule 21 specifies maximum generator size relative to the peak load at the point of interconnection at 15%. So, for example, if a generator is interconnected on the low side of a distribution substation bank with a peak load of 20 MW, the maximum Rule 21 interconnection criteria would allow a 3 MW system (3 MW = 15% * 20 MW).
>
> However, the 15% criterion, which is established for all generators regardless of type, was adjusted to 30% for the purposes of determining the technical potential of PV. The 15% limit is established at a level where it is unlikely the generator would have a greater output than the load at the line segment, even in the lowest load hours in the off-peak hours and seasons (such as the middle of the night and in the spring). Since the peak output for photovoltaics is during the middle of the day, PV is unlikely to have any output when loads are lowest. Therefore, a 30% criterion was used for technical interconnection potential estimates. The discussion was held with utility distribution engineers, however, we did not consider formal engineering studies or Rule 21 committee deliberation since the purpose of the analysis was only to define potential.

As a component of the distributed PV renewable auction mechanism (RAM) program development process, the CPUC requested data on peak loads at all IOU substations from the IOUs and compiled that information graphically as shown in Figure 11-3. According to the CPUC, this data was obtained from IOU distribution engineers.[370] Approximately 13,300 MW of PV can be connected directly to IOU substation load banks based on the data in Figure 11-3. The supporting calculations for this estimate are provided in Table 11-1.

Figure 11-3. IOU Substation Peak Loads, 30 Percent of Peak Load



The IOUs provide about two-thirds of electric power supplied in California, with POUs like the Bay Area POUs, SMUD, LADWP, and others providing the rest.[371] Assuming the substation capacity pattern in Figure 11-3 is also representative of the non-IOU substations, the total California-wide distributed PV that could be interconnected at substation low-side load banks with no substantive substation upgrades would be [13,300/(2/3)] = 19,950 MW.

Table 11-1. Calculation of Distributed PV Interconnection Capacity to Existing IOU Substations with Minimal Interconnection Cost

Substation range	Number of substations	Calculation of distributed PV that could be interconnected with minimal substation upgrades (MW)	Total distributed PV potential (MW)
1-200	200	average peak ~60 MW x 0.30 = 18 MW	3,600
201-500	300	average peak ~45 MW x 0.30 = 13.5 MW	4,000
501-800	300	average peak ~30 MW x 0.30 = 9 MW	2,700
801-1,000	200	average peak ~20 MW x 0.30 = 6 MW	1,200
1,001-1,600	600	average peak ~10 MW x 0.30 = 3 MW	1,800
		Distributed PV total:	13,300

11.2 Upgrading Distribution System to Maximize Distributed PV

An upgrade at the substation would be necessary to accommodate back-flow in cases where a large amount of distributed PV is interconnected to single substation equipped with conventional one-way safety devices. An example would be a warehouse district with clusters of large rooftops covered with PV, that collectively could produce up to 100 percent of a substation's peak load. The safety devices on a typical 100 MW, 12 kV/69 kV substation can readily be upgraded to allow two-way power flows, also known as bidirectional power flows, for up to 100 MW of interconnected distributed PV.

PG&E is already addressing the transmission and distribution grid equipment and communication issues that could restrict the full development of rooftop PV potential in the Bay Area. The circuit breakers on over 50 percent of PG&E's 724 distribution substations are equipped with full microprocessor control.[372] 100 percent of all critical PG&E distribution substation circuit breakers will be microprocessor-controlled by 2015. Voltage optimization controls are being installed on 400 distribution feeders with high levels of PV generation or high distribution system losses. PG&E is largely resolving, through its *Smart Grid Deployment Plan 2011-2020*, distribution grid issues that could otherwise restrict rapid development of the Bay Area's full rooftop PV potential.

A distribution substation upgrade would consist of retrofitting substation metering and microprocessor-controlled protective equipment from one-way power flow to bidirectional power flow. The cost of such an upgrade for a typical 100 MW distribution substation would be approximately $500,000.[373] This is well under 1 percent of the gross capital cost of 100 MW of state-of-the-art PV at 2011 prices.

The cost to build a new 100 MW, 12 kV/69 kV substation is in the range of $25 million.[374] Even the cost of a new 100 MW distribution substation, at $25 million, is less than 10 percent of the gross capital cost of 100 MW of state-of-the-art PV at 2011 prices. The substation upgrade cost would be relatively minor compared to the gross capital cost of 100 MW of PV arrays, and would not present a substantive financial hurdle to developing a 100 MW distributed PV resource concentrated in an area served by a single existing distribution substation.

The CPUC assumes that larger PV arrays will be connected directly to the substation low-side 12 kV load bank. SDG&E estimated that the cost of a 10 MW feeder is $0.6 million per mile.[375] The cost of a 3-mile long dedicated feeder from multiple rooftop PV arrays with a combined capacity of 10 MW to the low-side bus of the substation would be less than $2 million.

The current capital cost of large commercial rooftop PV is in the range of $3,500/kW$_{dc}$.[376] This is equivalent to a cost of approximately $4,400/kW$_{ac}$.[377] The gross capital cost of 10 MW of rooftop PV at $4,400/kW$_{ac}$ would be $4,400/kW$_{ac}$ x (1,000 kW/MW) x 10 MW$_{ac}$ = $44 million. The cost to construct a dedicated feeder to interconnect 10 MW$_{ac}$ of rooftop PV would be approximately 5 percent of the gross project capital cost. This is a relatively minor cost and does not represent a financial impediment to maximizing the development of distributed PV resources.

11.3 Monitoring Grid-Connected Distributed PV

A December 2011 analysis on the integration of renewable distributed generation, conducted for the CEC, determined that accommodating back-flow conditions caused by large amounts of distributed generation on distribution circuits would not require major changes to California's basic distribution infrastructure.[378]

A primary concern expressed in the analysis is the lack of significant utility effort in California to monitor or control the dispatch of non-utility owned rooftop PV on distribution circuits. The monitoring and dispatch control of commercial-scale rooftop PV is considered essential to reliable grid operation in Germany, where approximately 25,000 MW_{dc} of distributed PV was online at the beginning of 2012.

The analysis prepared for the CEC states:[379]

> Unlike Germany, the California ISO has no visibility of the energy production of DG resources connected to the distribution system and cannot send dispatch commands to these DG resources. This is especially true for DG resources that are connected behind the meter at a customer site and the DG output is netted with the customer load. By virtue of its balancing area authority status, the California ISO must be prepared to cover the total load at the customer site in the event that the DG unit shuts down, but the amount of load being offset by DG output is typically unknown to the California ISO.
>
> The European experience shows that it is vital for the power system operator to be able to monitor the output of DG facilities as well as direct DG units to curtail dispatch when required for emergencies, such as grid reliability and safety.[380]

This analysis indicates that the current limitation on DG inflows is more administrative than technical, especially in light of PG&E's progress in upgrading distribution grid safety devices to microprocessor control.

11.4 Use of Smart Inverters in All PV Systems

Traditionally PV inverters were intentionally designed to feed as much active power, in kW or MW, as available from the solar array at unity power factor into the grid. More recently utilities and independent power providers have shown much interest in the three phase inverter's capability to also absorb and provide reactive power from and to the grid.[381]

The flow of active power and reactive power in the grid are independent from one another and largely require different control schemes. Active power control is tied to controlling grid frequency, whereas reactive power control is linked with controlling the grid voltage.

11.4.1 Control of Active Power and Frequency

In a transmission and distribution network it is necessary to keep the frequency as stable as possible because the biggest generating resources, all of which are synchronous machines, work at their most efficient point when spinning at exactly 60 cycles per second. Also, the speed governors on these machines must operate in lock-step to share the generation load between machines to meet demand. For the frequency to remain stable the generated active power must match the power demand at all times. However, many electricity consuming devices operate out-of-synch with a standard alternating current waveform where the current and voltage waveforms are synchronized. The degree of synchronization between the current and voltage waveforms is called the "power factor." When current and voltage are not in synchronization, for example because an electricity consuming device creates induction, this "out of synchronization" effect must be countered with reactive power. Some loads requiring offsetting reactive power are shown in Table 11-2.

Table 11-2. Typical Reactive Power Consuming Loads[382]

Load	Power factor
Fluorescent lighting	0.90
Heat pump and A/C	0.83
Washer	0.65
Industrial motor	0.85

11.4.2 Control of Reactive Power and Alternating Current Voltage

Although reactive power can be controlled in large generation stations, it is necessary to control voltage by injecting and absorbing reactive power at various points throughout the transmission and distribution network. Excessive voltage can adversely affect equipment and loads. Reactive power control also greatly enhances grid stability and reduces line transmission losses.

Transmission lines can, depending on load and length, either absorb or provide reactive power. The resistive power loss component, heat loss, is often insignificant in comparison to the reactive power component at very high voltage levels.

The reactive power capacity of a smart PV inverter can be used as a fast-acting static reactive power compensator, controlled through a supervisory control and data acquisition system. A major benefit of this implementation is that it comes at very little additional component cost. At the distribution line level, smart PV inverters are used to correct the power factor by providing reactive power close to where they are being used, rather than importing them from far away. Transformers and most electrical loads are inductive in nature and therefore consume reactive power.[383]

Traditionally power factor correction is done by connecting large, paralleled capacitor banks to many of the voltage levels of the distribution system. These capacitors are strategically placed to adjust voltage along the feeder. Power factor correction and alternating current voltage regulation can be performed much more economically by distributed three-phase smart PV inverters along the feeder. This regulation will also be done in a continuous and smooth fashion, without any step changes or noticeable switching events.[384]

Germany requires PV inverters on systems 100 kW or greater in capacity to utilize smart PV inverters.[385] This same requirement should be applied in California to assure that high levels of power flow from rooftop PV systems will maintain or improve grid reliability.

11.5 IOUs and Distributed PV

In its March 2008 application to the CPUC for an urban PV project up to 500 MW, SCE expressed a high level of confidence that it can absorb thousands of MW of distributed PV without additional distribution substation infrastructure. SCE indicated that "SCE's Solar PV Program is targeted at the vast untapped resource of commercial and industrial rooftop space in SCE's service territory,"[386] and "SCE has identified numerous potential (rooftop) leasing partners whose portfolios contain several times the amount of roof space needed for even the 500 MW program."[387]

The utility stated it has the ability to balance loads at the distribution substation level to avoid having to add additional distribution infrastructure to handle this large influx of distributed PV power.[388] SCE explains:

> SCE can coordinate the Solar PV Program with customer demand shifting using existing SCE demand reduction programs on the same circuit. This will create more fully utilized distribution circuit assets. Without such coordination, much more distribution equipment may be needed to increase solar PV deployment. SCE is uniquely situated to combine solar PV Program generation, customer demand programs, and advanced distribution circuit design and operation into one unified system. This is more cost-effective than separate and uncoordinated deployment of each element on separate circuits.[389]

SCE also noted that it will be able to remotely control the output from individual PV arrays to prevent overloading distribution substations or affecting grid reliability:[390]

> The inverter can be configured with custom software to be remotely controlled. This would allow SCE to change the system output based on circuit loads or weather conditions.

As SCE states, "Because these installations will interconnect at the distribution level, they can be brought on line relatively quickly without the need to plan, permit, and construct the transmission lines."[391] This statement was repeated and expanded in the CPUC's June 18, 2009 press release regarding its approval of the 500 MW SCE urban PV project:[392]

> Added Commissioner John A. Bohn, author of the decision, "This decision is a major step forward in diversifying the mix of renewable resources in California and spurring the development of a new market niche for large scale rooftop solar applications. Unlike other generation resources, these projects can get built quickly and without the need for expensive new transmission lines. And since they are built on existing structures, these projects are extremely benign from an environmental standpoint, with neither land use, water, or air emission impacts. By authorizing both utility-owned and private development of these

> projects we hope to get the best from both types of ownership structures, promoting competition as well as fostering the rapid development of this nascent market."

The CPUC made a similar observation with its approval of the PG&E 500 MW distributed PV project in April 2010:[393]

> This solar development program has many benefits and can help the state meet its aggressive renewable power goals," said CPUC President Michael R. Peevey. "Smaller scale projects can avoid many of the pitfalls that have plagued larger renewable projects in California, including permitting and transmission challenges. Because of this, programs targeting these resources can serve as a valuable complement to the existing Renewables Portfolio Standard program.

The use of the term smaller scale in the CPUC press release is a misnomer. A 500 MW distributed PV project is the same size as a 500 MW solar thermal project at a remote desert site. Individual rooftop PV arrays in a large distributed PV project are functionally equivalent to single rows of reflective mirrors in a solar thermal project. Each rooftop or row is a contributor to a much bigger whole.

11.6 Conclusions and Recommendations

- IOUs spend about two-thirds of their total capital budgets on distribution system upgrades and new infrastructure.

- Existing California feeders and distribution substations can absorb up to approximately 20,000 MW of distributed PV without significant modification.

- The cost of upgrading a 100 MW distribution substation to full bidirectional flow is in the range of $500,000 or less. This is well under 1 percent of the cost of the potential rooftop PV capacity that could be connected to the substation. Much of the necessary microprocessor-controlled hardware is already being installed by PG&E as part of its smart grid deployment plan.

- California IOUs are not monitoring or controlling third party DG on their distribution circuits. This DG monitoring and control function is considered critical to ensure grid reliability in European countries with high levels of DG.

- IOUs state they will employ advanced distribution circuit design and operation to handle large influxes of PV power from their IOU-owned distributed PV. This same approach should be used by PG&E to monitor and control third-party DG on its distribution circuits.

- The CEC recommends that new distribution substations and existing substations to be upgraded must include advanced grid technologies that will support grid flexibility. This would include full bidirectional flow capability.

- PG&E and Bay Area POUs should be required, consistent with the SB 17 smart grid mandate, to include advanced grid technologies, including full bidirectional flow capability, in all substations and associated feeders with a near- or mid-term potential for high levels of DG development.

- Smart inverters should be required on all PV systems to assure high power quality and to permit the utility to monitor and control the inverter as needed to maintain grid reliability.

- Rule 21 should be revised to increase the minimum DG “easy interconnection” limit to 30 percent of substation peak load for PV.

- Rule 21 should not apply to distribution substations and associated feeders that are equipped with the microprocessor-controlled hardware and monitoring necessary to be fully bidirectional.

12. Bay Area PV Technical Potential

12.1 Potential of Rooftops, Parking Lots, Substations

There is about 18,000 MW_{ac} of PV potential in the Bay Area on rooftops, commercial parking lots, and at non-urban substations. Of this total, about 16,700 MW_{ac} is rooftop and commercial parking lot PV potential as summarized in Tables 12-1 and 12-2. Approximately 1,600 MW_{ac} of additional PV could be developed in arrays up to 20 MW at non-urban substations in the Bay Area. The quantity and distribution of these substation PV arrays around the Bay Area is shown in Table 12-3.

Moscone Center rooftop PV array. Photo: SFPUC.

Table 12-1. Estimate of Rooftop and Parking Lot PV Potential in Bay Area[394,395]

County and 2009 population	Residential (MW_{ac})	Commercial (MW_{ac})	Commercial parking lot (MW_{ac})	Total (MW_{ac})
Alameda 1,480,000	1,360	879	1,525	3,764
Contra Costa 1,036,000	756	438	1,070	2,264
Marin 249,000	180	111	260	551
Napa 134,000	100	78	140	318
San Francisco 810,000	453	635	835	1,923
San Mateo 714,000	431	465	735	1,631
Santa Clara 1,771,000	1,278	1,129	1,825	4,232
Solano 411,000	331	190	425	946
Sonoma 470,000	375	230	485	1,090
Total	5,264	4,155	7,300	16,719

The PV potential of open ground-level parking lots or parking structures have not been included in statewide PV potential assessments to date, despite a rapid increase in the number of parking lot PV arrays. An estimate of the PV potential of parking areas and parking structures is necessary to develop a complete understanding of the PV potential in the Bay Area. This estimate is provided in Table 12-1.

Parking lot, Milpitas High School. Photo: New York Times, *In California, carports that can generate electricity*, Nov. 25, 2010.

The methodology utilized to calculate the PV technical potential of ground-level parking lots and parking structures is shown in Table 12-2. San Francisco is used as an example in the table. A core assumption in the methodology is that only 25 percent of total estimated parking surface is sufficiently open, meaning not shaded to a significant degree, so that its full solar potential can be realized. The estimated ground-level parking lot and parking structure PV potential in San Francisco, assuming 25 percent of the total surface area is utilized for PV, is 835 MW. This same calculation methodology is applied to the population of each Bay Area county to determine the parking lot PV estimates included in Table 12-1.

Table 12-2. Assumptions Used to Estimate PV Potential of Parking Lots – San Francisco

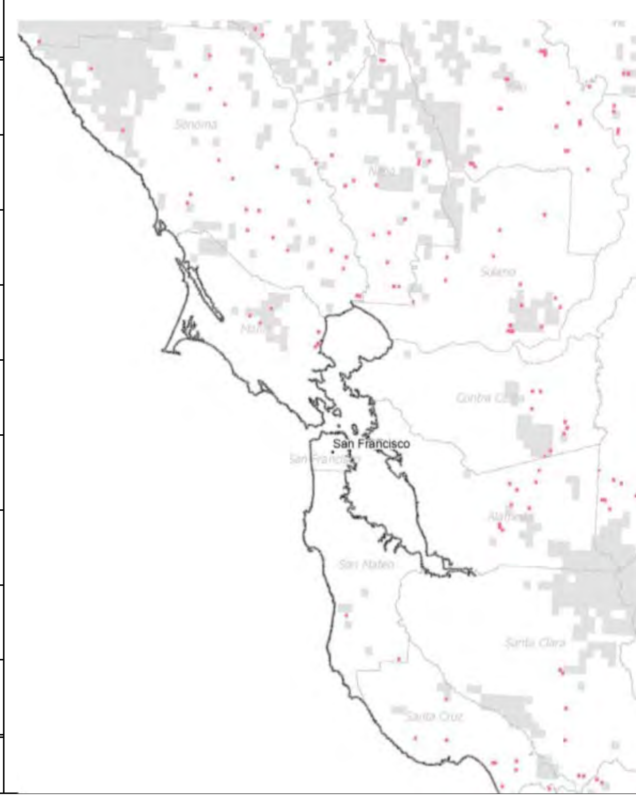
Assumption	Source
771 vehicles per 1,000 citizens	Dr. Donald Shoup, urban planning, UCLA[396]
At least 4 parking spaces per vehicle, one of which is residential space	Dr. Donald Shoup, urban planning, UCLA
810,000 people	Approximate San Francisco population, 2009 Moody's www.economy.com population data
162 square feet per parking space	Square footage of typical 9-foot by 18-foot parking space, Envision Solar, San Diego[397]
Approximately 1,874,000 non-residential parking spaces in San Francisco	Calculated value: 810,000 × (771/1,000) × 3 spaces [4 total spaces per car – 1 residential space per car]
11 W_{ac} per square foot PV capacity per square foot of parking area	Envision Solar, San Diego
3,339 MW_{ac} parking lot PV theoretical potential without considering shading	Calculated value: 1,874,000 spaces × 162 square feet per space × 11 W_{ac} per square feet × 1 MW_{ac} per million W_{ac}
835 MW_{ac} actual potential	Rough estimate of actual PV potential - assumes 25 percent of non-residential parking spaces are unshaded throughout the day and full PV potential can be realized at these sites

RETI evaluated the potential of distributed 20 MW_{ac} PV arrays located at non-urban substations around the state in 2008.[398] An initial screening conducted by the RETI contractor, Black and Veatch, determined that 20 MW_{ac} PV arrays could potentially be developed at 1,375 rural substations around the state. This is a total of 27,500 MW_{ac} of PV potential. As shown in Table 12-3, 1,640 MW of this potential is located in the Bay Area. Each orange square in the graphic associated with Table 12-3 represents 20 MW_{ac} of PV capacity.

PG&E's 2 MW Vaca-Dixon PV project. Photo: CPUC 1st Quarter 2010 RPS Status Report to Legislature, p. 3.

Table 12-3. RETI Estimate of Rural Substation PV Potential in Bay Area[399]

County	PV potential of non-urban substations (MW_{ac})
Alameda	180
Contra Costa	160
Marin	120
Napa	300
San Francisco	0
San Mateo	40
Santa Clara	120
Solano	260
Sonoma	460
Total	1,640



The U.S. EPA has also developed a nationwide inventory of brownfield sites that are potentially suitable for renewable energy development. The EPA inventory includes dozens of sites in the Bay Area totaling thousands of acres.[400] Many of these sites are suitable for the deployment of PV arrays.

12.2 Existing Distributed PV Programs

Table 12-4 summarizes the capacity of existing approved distributed PV programs in California and the approximate completion date of these programs. The *California Solar Initiative* is the largest of these PV programs and the only program where the PV capacity is not RPS-eligible.[401]

Table 12-4. Current Status of California Distributed PV Programs

PV project underway	Capacity (MW_{ac})	Completion date
California Solar Initiative	3,000	2016
Utility distributed PV (PG&E 500 MW_{dc}, SCE 500 MW_{dc}, SDG&E 100 MW_{dc})	~900	2014
SB 32 Feed-In Tariff	750	2014
CPUC Renewable Auction Mechanism[402]	1,000	2014
SMUD Feed-In Tariff	100	2012
LADWP Feed-In Tariff (proposed)[403]	150	2016
Total committed DG PV	~5,900	by 2016

The proportion of existing California distributed PV programs that will be built in the Bay Area, assuming the capacity that is built is proportional to the demand, is provided in Table 12-5.

Table 12-5. Estimate of Distributed PV Capacity to be Located in Bay Area[404]

PV project underway	PG&E allocation (MW_{ac})	Estimated PG&E Bay Area allocation (MW_{ac})
California Solar Initiative[405]	921	550
PG&E 500 MW_{dc} distributed PV	~400	~240
SB 32 Feed-in Tariff [406]	250	150
CPUC Renewable Auction Mechanism[407]	421	250
Total estimated DG PV in Bay Area	~2,000	~1,200

12.3 Detailed Inventories of Commercial PV Potential

A number of studies have been conducted in California's principal urban centers to inventory the square footage of residential and commercial building roof space available for PV. An inventory of residential and commercial roof space in Los Angeles was prepared as a component of the UCLA/Los Angeles Business Council (UCLA/LABC) PV study in 2010.[408]

An inventory of available commercial roof area was completed in San Diego in 2005.[409] Figure 12-1 shows how commercial rooftops were classified to determine PV capacity in the San Diego study. Black & Veatch also conducted a limited inventory of commercial rooftops near existing urban substations in the Bay Area and the Los Angeles Basin in 2009 as part of the CPUC's Re-DEC process.[410]

Figure 12-1. Inventory of Commercial Rooftop PV Potential – Classification of Rooftops

12.4 Conclusions and Recommendations

- Bay Area rooftop and parking lot PV potential, at over 16,000 MW_{ac}, far exceeds the BASE 2020 PV target of 3,600 MW_{ac}.

- Existing rooftop and distributed PV programs will add approximately 1,250 MW_{ac} of capacity to the Bay Area by 2016. This is about one-third of the BASE 2020 target of 3,600 MW_{ac}.

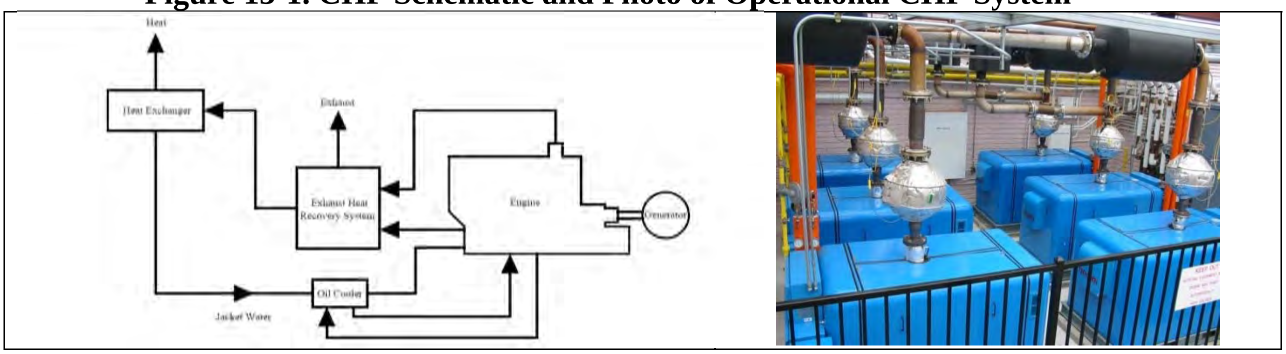
- Detailed quantification of roof-by-roof commercial PV potential and commercial-scale parking lot potential should be conducted by all cities and counties in the Bay Area.

13. Combined Heat and Power (CHP)

13.1 CHP Basics

CHP, also known as cogeneration, follows energy efficiency and renewable energy in the *Energy Action Plan* loading order. CHP systems can combust biogas or biomethane to qualify as renewable energy power systems. The key to the high efficiency of a CHP system is conversion of the heat in the hot exhaust gas generated by an engine, turbine, or fuel cell to steam or hot water for use in heating and cooling processes. CHP systems improve efficiency by significantly reducing the total natural gas, biomethane, or biogas consumption that would otherwise be necessary to produce heat or electric power in two separate systems. A schematic of a small CHP system is shown in Figure 13-1.

Figure 13-1. CHP Schematic and Photo of Operational CHP System[411,412]



Typical natural gas-fired electric generators convert from 35 percent, in the case of boilers and peaking gas turbines, to 55 percent, in the case of state-of-the-art baseload combined cycle plants, of the fuel's thermal energy into electricity. 45 to 65 percent of the heating value of the natural gas fuel goes unused and is released into the environment as waste heat. California's older steam boiler power plants and nuclear reactors use many millions of gallons of seawater a day in once-through cooling systems to remove this heat. Wet cooling towers and air-cooled condensers are also used to remove the waste heat.

Nearly all of the CHP systems in operation in the Bay Area use either internal combustion engines or gas turbines, though fuel cells are becoming more common.[413] The heat in the exhaust gas of these combustion units is used to heat the air in buildings, provide hot water or steam, drive a dehumidifier, or drive an absorption chiller to provide refrigeration and cooling. With this large range of uses for the exhaust heat, any building with a significant heating and/or cooling load is a candidate for CHP. CHP systems can achieve overall thermal efficiencies in the range of 80 to 90 percent.

13.2 CHP in California

There are approximately 8,800 MW of operational CHP plants in California. The market distribution of these plants is shown in Figure 13-2. The market distribution within the industrial and commercial CHP categories is provided in Figure 13-3.

Figure 13-2. Market Distribution of All Classes of CHP in California[414]

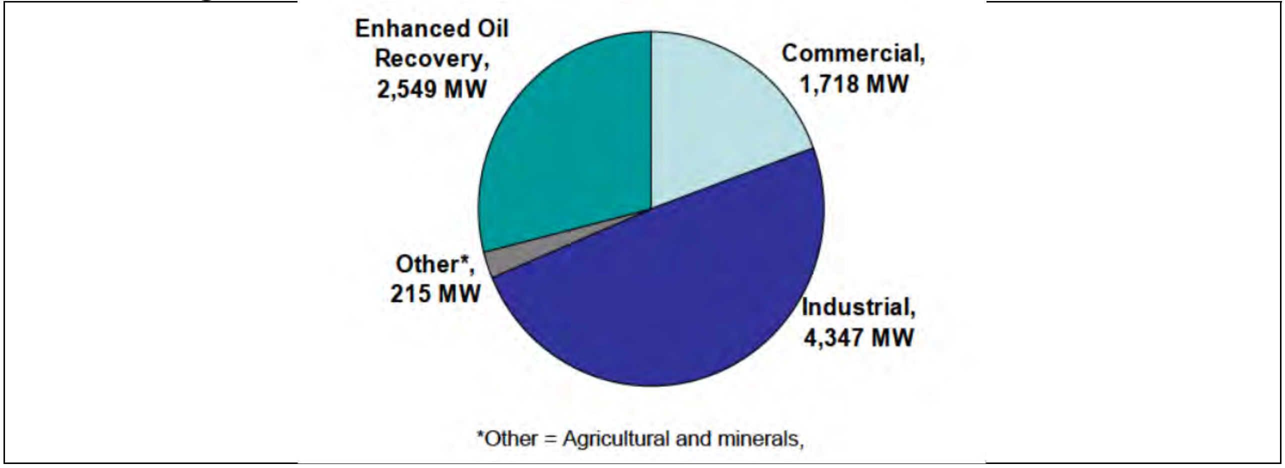
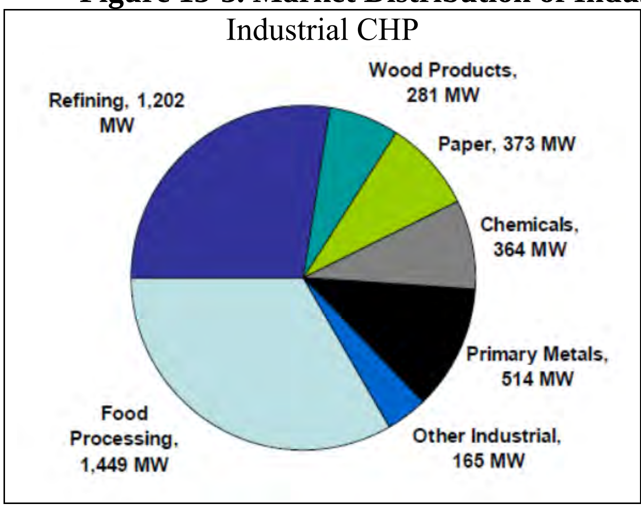
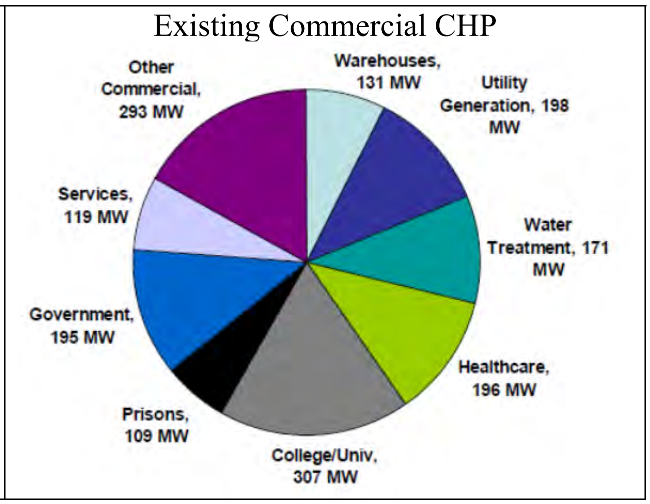


Figure 13-3. Market Distribution of Industrial and Commercial CHP in California



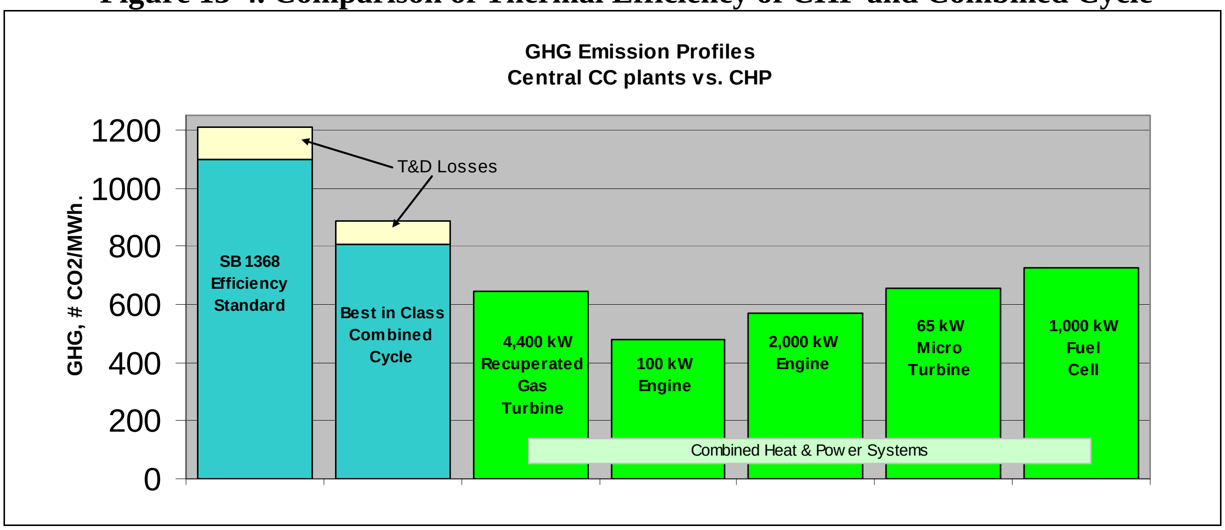


The carbon footprint of boiler plants and simple-cycle natural gas-fired peaking turbines is approximately 1,100 lb CO_2/MWh.[415] The carbon footprint of a baseload natural gas-fired combined cycle plant is approximately 820 lb CO_2/MWh.[416] However, California combined cycle plants have a relatively moderate capacity factor on average, in the range of 65 percent, indicative of a "load following" operating pattern that is less fuel efficient than baseload operation.[417]

Operating at partial load significantly reduces the efficiency of the combined cycle plant. The efficiency drops about 10 percent relative to baseload operation when the combined cycle plant is operating at 50 percent load.[418] As a result, a combined cycle unit operating a substantial amount of time at part load could be expected to have an average CO_2 emission factor in the range of 860 to 900 lb CO_2/ MWh, or about 5 to 10 percent higher than the baseload CO_2 emission rate.

The carbon footprint of a properly designed baseload CHP plant can be as low as 500 lb CO_2/MWh on natural gas.[419] Properly designed in this context means the CHP plant is sized for the minimum thermal load at the site to ensure the plant is always operating at maximum efficiency. Properly designed CHP systems have a substantially lower carbon footprint than state-of-the-art combined cycle power plants. Figure 13-4 provides a comparison of the carbon footprint of several CHP alternatives to that of a baseload combined cycle power plant.

Figure 13-4. Comparison of Thermal Efficiency of CHP and Combined Cycle[420]



13.3 4,000 MW of New CHP by 2020 – 840 MW in Bay Area

The *AB 32 Scoping Plan* target is 4,000 MW of new CHP in California by 2020.[421] The economic potential for new CHP in California was identified as 6,500 MW by 2030 in the ICF International April 2010 report prepared for the CEC on California CHP potential.[422]

Governor Brown has called for the addition of 6,500 MW of CHP in California by 2030 in his *Clean Energy Jobs Plan*. The AB 32 target of 4,000 MW of new CHP by 2020 is consistent with a 2030 target of 6,500 MW of new CHP.

Achievement of this potential will require the implementation of a CHP payment that assures CHP projects can be financed. A proposed payment threshold for CHP is discussed in Chapter 14.

The nine Bay Area counties accounted for about 21 percent of net statewide electricity demand in 2008.[423,424] The proportion of new CHP installations in the Bay Area by 2020, assuming that the new CHP capacity installed is proportionate to Bay Area electricity consumption, would be 0.21 × 4,000 MW = 840 MW.

The BASE 2020 target for new CHP is 840 MW. Table 13-1 identifies the approximate amount of new CHP that would installed in each Bay Area county, assuming CHP capacity is installed proportionate to county electricity demand, to meet the target of 840 MW of new CHP by 2020.

Table 13-1. Estimate of New CHP Installed in Each Bay Area County to Achieve 840 MW of New CHP by 2020

County	Electricity Consumption in 2008[425] (GWh)	Fraction of total Bay Area electricity consumption in 2009	Distribution of 840 MW of new CHP in Bay Area by 2020 (MW)
Marin	1,482	.03	25
Napa	1,038	.02	17
Sonoma	2,970	.05	42
Solano	3,232	.06	50
Contra Costa	9,014	.16	134
Alameda	11,682	.20	168
Santa Clara	17,088	.29	244
San Mateo	5,116	.09	76
San Francisco	5,694	.10	84
Total	57,316	1.00	840

13.4 CHP Case Study - San Francisco

CHP represents a sizable local generation resource in San Francisco. Over 60 MW of CHP capacity is already in operation in the city according to a city-sponsored CHP study.[426] This capacity includes the San Francisco Airport 30 MW gas turbine CHP plant, the UC San Francisco 13.5 MW gas turbine CHP plant, twenty internal combustion engine CHP plants all under 2 MW, three microturbine CHP plants at 240 kW or less each, and one 250 MW fuel cell plant. The study identified the potential for at least 106 additional MW of CHP in San Francisco.

CHP opportunities also exist where natural gas is already used to produce steam. One project that has been under consideration for nearly a decade is a 50 MW CHP plant in downtown San Francisco. The city currently has a steam franchise agreement with NRG Thermal Corporation to produce steam at the 5th and Jessie plant between Market and Mission.[427] The existing plant consists of relatively low efficiency steam boilers that provide steam for heating and cooling to 170 buildings in downtown San Francisco as shown in Figure 13-5.

A gas turbine would be added to the NRG steam plant to produce electricity. Waste heat from the turbine would be used to produce steam in the existing boilers to supply the district heating and cooling system. This one CHP plant, at 50 MW capacity, would provide 60 percent of the 84 MW of new CHP allocated to San Francisco in BASE 2020. A simplified schematic of the NRG steam plant and the downtown San Francisco steam loop is also shown in Figure 13-5.[428]

Figure 13-5. NRG San Francisco Energy Center and Downtown San Francisco Steam Loop

The San Francisco CHP study also identifies the categories of facilities where the 106 MW of additional CHP capacity would be located. These facility categories are shown in Table 13-2. This capacity does not include the 50 MW CHP addition to the NRG steam plant.

Table 13-2. Additional CHP Potential in San Francisco

Facility Type	CHP Potential (MW)
Hotels	20
Hospitals	4
Data centers	Significant (unquantified)
Office buildings	80
Universities	Most have CHP already, though potential for expansion/addition
Schools	Significant (unquantified)
Residential high rises	> 2
Wastewater treatment plants	Both plants have CHP
Health/fitness centers	Significant (unquantified)
Miscellaneous	Significant (unquantified) This category includes USPS distribution centers, warehouses with large heating or cooling loads.

The CHP potential identified in the study is for many small CHP plants in the 1 MW range or less. Small CHP plants will generally incorporate an internal combustion engine, microturbine, or fuel cell.

A 250 kW fuel cell is in operation at a U.S. Post Office distribution center in San Francisco.[429] Larger fuel cell CHP installations are in operation in other parts of California. For example, the Sheraton Hotel and Marina Hotel in San Diego has a long-term agreement with Alliance Power for a 1.5 MW stationary fuel cell power plant that supplies 70 percent of the hotel's electric power demand. The waste heat from the units is used to heat swimming pools and for domestic water heating. The plant consists of two fuel cells, a 1 MW unit and a second 0.5 MW unit. The 1 MW unit went online in December 2005, the 0.5 MW unit in mid-2006.[430]

Numerous Bloom Energy solid oxide fuel cells are now in operation in the Bay Area. The first commercial Bloom Energy 100 kW fuel cells were shipped to Google in July 2008 for use at its Mountain View campus.[431] As of January 2011 Bloom Energy had installed 200 of its 100 kW fuel cells in California. Bloom also provides customers with the option to utilize biogas or biomethane in the units. For example, twenty 100 kW units are being installed at California Institute of Technology (CalTech). About half the gas to be used at the CalTech installation will be offset by biogas purchases.[432]

Microturbines combined with absorption chillers are another CHP option. United Technologies markets microturbine-absorption chiller packages under the trade name "PureComfort®." Systems are offered at 240 kW, 300 kW, and 360 kW. The hot exhaust gas is utilized in an absorption chiller/heater. The efficiency of this system can reach 90 percent. A PureComfort® system is in operation at the Ritz-Carlton Hotel in San Francisco.[433]

13.5 How CHP Fits in DG Strategy

CHP provides a reliable continuous source of power to counterbalance the non-continuous output of wind and solar energy systems. An increase in local CHP reduces congestion on existing transmission lines and eliminates the transmission losses associated with power imports. It also removes load from the grid, reducing demand pressure to add new peaker plants or other generation and transmission infrastructure. The benefits of CHP include:

- Reduced need to purchase grid electricity
- Reduced reliance on transmission system
- Reduced natural gas consumption
- Reduced CO_2 emissions
- Local, reliable round-the-clock baseload electricity

CHP reduces natural gas demand by effectively using waste heat for heating or cooling. An example of the natural gas savings potential of CHP is provided in Appendix F for a 60 kW CHP system in Richmond, California.

13.6 Obstacles to Increasing CHP Use in Bay Area

For financial reasons, IOUs prefer to sell power to customers from: 1) the IOU's own generation assets, or 2) more distant third party providers that is transmitted over IOU-owned transmission lines. Buying power from its customers runs counter to core IOU financial interest – the construction of new IOU-owned generation and transmission infrastructure. Construction of new infrastructure is the primary mechanism available to the IOU to increase its revenue stream. The cost of this infrastructure, including a guaranteed rate of return to the IOU in the range of 11 to 12 percent, is borne by ratepayers.[434] The removal of significant amounts of load from the grid, caused by IOU customers installing CHP, will over time undercut the need for new sources of IOU revenue.

Interconnecting CHP with the utility distribution system has been an obstacle for some CHP developers. The experience of CHP developer Tecogen is instructive. A 60 kW Tecogen CHP plant has been in successful operation at 1080 Chestnut Street, a residential high-rise on Russian Hill in San Francisco, since 1988. According to an independent energy auditor, the system resulted in $400,000 in energy savings in the 1991-2000 period when natural gas prices were very low relative to current prices.[435] Yet this is the only Tecogen system in San Francisco. The following quote summarizes the difficulties Tecogen has encountered attempting to develop CHP projects in California:[436]

> Just a few years ago, Bob Panora was a sort of DE (distributed energy) poster child, embodying a whole segment of power-project developers shut out of markets, at least in part due to contrived utility obstacles. In testimony presented to the California Energy Commission at that time, Panora, president and chief operating officer of Massachusetts-based Tecogen Inc., told commissioners of being made to run a gauntlet of technical hurdles time and again to get his company's 75-kW CHP engines grid-connected—only to be shot down in the end on one pretext or another.
>
> Partly as a result of Panora's accounts, things soon began improving for DE developers. Changes to California's Rule 21 on interconnections were implemented in 2006, forcing utilities to lower some barriers.

The quote is from a Distributed Energy Magazine article on a novel grid interconnection device incorporated into Tecogen cogeneration modules. The innovative Tecogen inverter-based controller was developed in part with CEC funding. It allows individual CHP modules to operate independent of the grid and each other while maintaining the ability to seamlessly reconnect with the grid at any time. As noted in the article:

> From a customer perspective, the result is indeed a "dream machine." It's an elegantly simple, inexpensive circuit of engines which a) can be positioned around a site for optimal CHP efficiency that will save money and b) will keep running robustly and automatically, powering critical services, regardless of what the grid does or doesn't deliver.

The control architecture for Tecogen CHP modules allows the Tecogen CHP systems to serve as autonomous micro-electric utilities, also known as microgrids. A 300 kW Tecogen CHP plant incorporating this microgrid capability, consisting of three 100 kW "In Verde" CHP modules, is currently being installed in the headquarters of SMUD.[437] See Figure 13-6. The system is expected to be operational in mid-2012.[438]

Figure 13-6. Tecogen 100 kW In Verde CHP

13.7 CHP Fuel Options

CHP technologies can use a wide variety of fuels to generate heat and power. The three primary candidate fuels are natural gas, biogas, and biomethane. Each of these fuel options is discussed in the following paragraphs.

Natural gas. Natural gas is currently the primary fuel used in CHP plants in the Bay Area. The natural gas infrastructure is well established and provides gas to most buildings in the region.

Biogas. Biogas is the gas produced by the anaerobic digestion of organic matter, typically at wastewater treatment plants and dairies, or from organic matter decomposition in landfills. Both forms of gas are referred to collectively as "biogas" in BASE 2020. Biogas is primarily composed of methane and CO_2, with trace amounts of nitrogen and hydrogen sulfide, and is produced and released into the atmosphere as a byproduct. Using this resource in a CHP system is an opportunity to take advantage of a fuel source that would otherwise be wasted. Biogas-fueled electricity is a significant percentage of Alameda Municipal Power electricity supply. Wastewater treatment plant digester biogas powers CHP plants at San Francisco's two wastewater treatment plants.[439,440]

The total generation capacity from the existing 42 California landfill gas-to-electricity projects is about 210 MW. There are 70 landfills that continue to flare the landfill gas they produce. These 70 landfills have the potential for producing approximately 66 MW. There are also 164 landfills that either do not have a landfill gas control system or are venting the landfill gas. These 164 landfills have the potential to produce approximately 30 MW.[441] The total remaining potential for landfill gas electricity generation in California is about 100 MW.

There are 2,700 dairies in California, but only 12 have digesters producing biogas.[442]

The CEC estimates California has between 450 and 600 MW of CHP electric generation potential from biogas produced from dairy, wastewater, and bio-waste digestion. The sources of this potential are shown in Table 13-3.[443]

Table 13-3. CHP Potential from Wastewater and Co-Digestion of Other Bio-Wastes

Resource type	Technical potential (MW)	Market potential (MW)
Wastewater	125	95
Restaurant fat, oil, and grease	10	8
Food processing waste	129	97
Dairy waste manure	334	250
Combined Total	598	450

The combined remaining potential of landfill biogas and dairy biogas in California is approximately 700 MW.

Internal combustion engines are the most common prime mover in biogas CHP systems. However, biogas fuel cell CHP systems are cost-competitive with retail electricity rates in California. This is due in part to the substantial incentive payment available, $4,500/kW, for fuel cells using renewable fuel under the Self Generation Incentive Program (SGIP).

The largest biogas CHP fuel cell system in California, providing 4.5 MW of electricity to UC San Diego and the City of San Diego, is being built under a turnkey third party power purchase agreement. UC San Diego will use the byproduct heat from the fuel cell generation as a continuous source for 320 tons of cooling capacity for its buildings. The fuel cell will be paired with an additional 2.8 MW advanced energy storage system, which will allow UC San Diego to store off-peak power and discharge the energy during peak-demand hours.[444]

Biomethane. The most straightforward option for the large-scale use of biogas in the Bay Area would be to upgrade the biogas where it is generated to biomethane for injection into the PG&E natural gas pipeline network. The upgrade process involves stripping-out the CO_2 and trace contaminants in the biogas. Biomethane has similar heating value and composition to pipeline quality natural gas.

PG&E took its first delivery of biomethane derived from a dairy digester in 2008.[445] PG&E also takes delivery of biogas from Microgy's Huckabay Ridge project in Texas.[446] The company did support federal bill H.R. 1158, The *Biogas Production Incentive Act of 2009*, which would have provided a federal tax credit of $4.27 per MMBtu for biomethane that can be injected into natural gas pipelines.[447] H.R. 1158 did not become law, and no subsidies or tax credits are currently available to biomethane producers for pipeline injection.[448]

Biomethane can be purchased by a CHP plant owner in California, injected into the natural gas pipeline system virtually anywhere in the Western U.S., and count as renewable fuel for RPS compliance purposes. For example, SMUD has a 15-year contract with a landfill operator near Dallas, Texas to provide 6 million cubic feet per day of biomethane for use in SMUD's Consumes combined-cycle plant.[449] 6 million cubic feet per day is sufficient to supply about 60 MW of CHP capacity, or about 7 percent of the new CHP target of 840 MW for the Bay Area.[450] This same contract arrangement used by SMUD could be used by CHP owner/operators in the Bay Area to operate a 100 percent renewable energy CHP plant.

13.8 State CHP Incentive Programs

The AB 1613 *Waste Heat and Carbon Emissions Reduction Act* was signed into law by former Governor Schwarzenegger in October 2007.[451] This legislation requires the IOUs to establish simple fixed clean energy payments for excess CHP electricity up to 20 MW at each site. POUs are required to: 1) establish programs that allow end-use customers to utilize CHP and 2) to provide a market for the purchase of excess CHP power at a just and reasonable rate.

AB 1613 also establishes a pay-as-you-save pilot program for eligible, non-profit customers. The pilot program enables the customer to finance all of the upfront costs for the purchase and installation of a CHP system by repaying these costs over time through on-bill financing at the difference between what an eligible customer would have paid for electricity and the actual savings derived for a period of up to 10 years. This is in essence a de facto PACE program for CHP. The IOUs must make on-bill financing of CHP available for up to a cumulative total of 100 MW of capacity. PG&E's estimated share of this 100 MW total is in the range of 45 MW.

SGIP provides incentives for fuel cells, distributed wind generation, and energy storage through 2012. Legislation to extend SGIP has been introduced.[452] The maximum system size is 5 MW. The minimum size is 30 kW for wind turbines and fuel cells using renewable fuels.[453]

13.9 Conclusions and Recommendations

- The Bay Area's proportion of the *AB 32 Scoping Plan* target of 4,000 MW of new CHP in California by 2020 would be approximately 840 MW.

- Biogas produced at California dairies is being upgraded to biomethane and injected into the PG&E natural gas pipeline system.

- Each Bay Area county government should identify and list existing in-county facilities using steam boilers to provide process heat. These lists of steam boiler facilities would form a priority list for conversion to CHP plants.

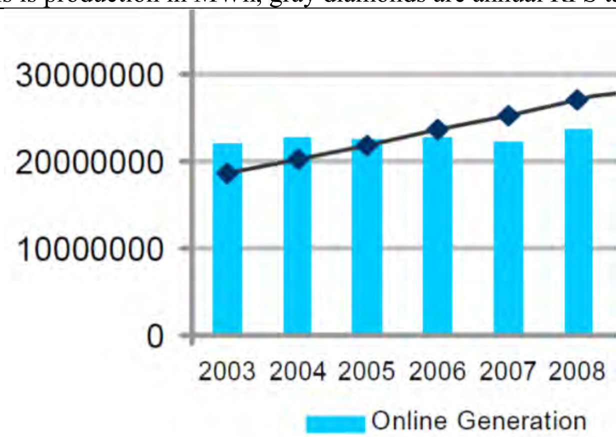
- New Bay Area CHP capacity should utilize at least 50 percent biogas or biomethane as a percentage of total heat input.

14. Clean Energy Payments

14.1 Background

The central issue in the debate over renewable energy and CHP in California is cost. The RPS standard was first mandated in 2002, establishing a 20 percent RPS target by 2017, and 1 percent per year progress increments.[454] The 2002 legislation clarified that the IOUs did not have to purchase renewable energy or meet RPS targets if the renewable resources cost more than electricity from a hypothetical baseload natural gas-fired power plant. This resulted in almost no net increase in RPS generation from 2003 through 2008, as shown in Figure 14-1.

Figure 14-1. RPS Electricity Production, 2003 - 2008[455]
(y-axis is production in MWh, gray diamonds are annual RPS targets)



The levelized cost-of-energy (LCOE) from a new natural gas-fired combined cycle unit is the representative market price of electricity that renewable energy resource costs are compared to in the California RPS program. This representative LCOE is called the "Market Price Referent" (MPR).[456] The MPR consists of the LCOE of a new combined cycle plant plus an adder of $15 per ton of CO_2 emissions.[457] The concept behind the MPR is that ratepayers should be protected from excessive green energy costs by requiring that renewable energy resources be no more costly than the new conventional natural gas-fired power that they would displace.

The Supplementary Energy Payments (SEP) program was also established in the original 2002 RPS legislation.[458] The SEP program was funded by the public goods charge, to provide a limited amount of funds to cover the above MPR costs of renewable energy projects. IOU RPS project development in California from 2003 through 2008 was effectively stalled due to: 1) relatively low value of the MPR, 2) ratepayer protection features which provided the IOUs with cost justification for not meeting RPS targets, and 3) limited SEP funds.

Meanwhile, 158 MW of third-party rooftop PV solar capacity came online in California in 2008 under the *California Solar Initiative* program.[459] The *California Solar Initiative* uses a retail net metering payment format (see Section 14.4). In contrast only 2 MW of RPS solar projects came online in 2008, the Southern California Edison 2 MW rooftop warehouse PV array in Fontana, California.[460]

SB 1036 (2007) effectively de-linked RPS contract pricing from the MPR. The chartered SB 1036 legislation states:[461]

> 25740.5.
> (a) The commission shall optimize public investment and ensure that the most cost-effective and efficient investments in renewable energy resources are vigorously pursued.
>
> (b) The commission's long-term goal shall be a fully competitive and self-sustaining supply of electricity generated from renewable sources.
>
> (e) The Legislature recommends allocations among all of the following:
>
> (4) Solar thermal generating resources that enhance the environmental value or reliability of the electrical system and that require financial assistance to remain economically viable, as determined by the commission.

Although the legislation directs the CPUC to ensure the most cost-effective and efficient investments in renewable energy, it is specifically instructing the CPUC to authorize contract terms for solar thermal projects that are sufficient for the projects to be economically viable.

California Public Utilities Code 399.15, which addresses RPS procurement requirements and spending limitations, states:[462]

> (c) The commission shall establish a limitation for each electrical corporation on the procurement expenditures for all eligible renewable energy resources used to comply with the renewables portfolio standard. In establishing this limitation, the commission shall rely on the following:
>
> (1) The most recent renewable energy procurement plan.
>
> (2) Procurement expenditures that approximate the expected cost of building, owning, and operating eligible renewable energy resources.
>
> (d) In developing the limitation pursuant to subdivision (c), the commission shall ensure all of the following:
>
> (1) The limitation is set at a level that prevents disproportionate rate impacts.
>
> (f) If the cost limitation for an electrical corporation is insufficient to support the projected costs of meeting the RPS procurement requirements, the electrical corporation may refrain from entering into new contracts or constructing facilities beyond the quantity that can be procured within the limitation, unless eligible renewable energy resources can be procured without exceeding a de minimis increase in rates, consistent with the long-term procurement plan established for the electrical corporation pursuant to Section 454.5.

The purpose of the cost limitation revisions codified in 399.15 is to assure that the power purchase agreement (PPA) terms are adequate for the project developer to demonstrate sufficient return to get the project financed and built. This is the same purpose of an adequate clean energy payment, or feed-in tariff, pricing structure.

Although confidential, the PPA terms for a number of projects have been reported publicly in the press. The reported contract pricing for some representative RPS solar projects is provided in Table 14-1.

Table 14-1. Contract Prices for Selected Utility-Scale Solar Projects Compared to MPR

Project	Capacity (MW)	Start-up date	PPA contract term (yr)	MPR,[463] 2009 ($/MWh)	PPA price[464] ($/MWh)	PPA price source
Genesis, solar thermal[465]	250	2013	25	112.45	163 (wet cool) 174 (dry cool)	Project Finance International,[466] Sept. 7, 2011
CA Valley Solar Ranch, PV[467,468]	250	2012	25	108.52	150 - 180	New York Times,[469] Nov. 11, 2011
Mojave, solar thermal	250	2014	25	116.36	~200	Forbes,[470] Nov. 10, 2011

The Mojave PPA, at approximately $200/MWh, was approved by the CPUC in November 2011. In contrast, the average PPA price that PG&E paid in 2011 for RPS PV projects in the 3-to-20 MW size category was $114/MWh.[471] The average PPA price that PG&E paid in 2011 for RPS PV projects in the 0-to-3 MW size category was $129/MWh.[472]

In the meantime, AB 1969 (2006) established a distributed renewable generation FIT program for projects up to 1.5 MW, with a 500 MW cap.[473] The AB 1969 FIT payment was set at the MPR. This FIT payment is currently $92.75/MWh for a 25-year contract with a 2012 start-up date (unadjusted for time-of-delivery).[474] The MPR FIT rate has been too low to finance DG PV projects under AB 1969.

The CPUC established a payment structure for excess PV production from net-metered PV systems in conformance with AB 920 (2009).[475] The net surplus compensation payment, equivalent to the short-term wholesale market price of electricity,[476] is about $0.04/kWh in PG&E territory.[477] This payment for point-of-use rooftop solar power is about one-quarter to one-fifth the rate determined as equitable by the CPUC for utility-scale solar thermal and solar PV projects listed in Table 14-1. The payment is less than one-half the 2011 MPR for renewable projects with a 25-year PPA starting operation in 2012.

SB 32 (2009) supersedes AB 1969 and expands the program cap from 500 MW to 750 MW and increases project size up to 3 MW.[478] SB 32 also directs the CPUC to establish a FIT tariff structure. The proposed rate structure for the SB 32 FIT is defined as the MPR California Public Utilities Code 399.20.[479]

To date the CPUC has been reluctant to significantly adjust the MPR to reflect other real costs associated with the generation and transmission of electricity from conventional power plants. However, the CPUC has taken steps to establish that it has the authority to set rates higher than the market reference price if those rates can be shown to be no higher than the "all-in" costs associated with a conventional generator.

The CPUC's attempt to set a FIT for small CHP less than 20 MW under AB 1613 (2007)[480] was challenged by California's IOUs as unlawful. The IOUs asserted that only FERC has the power to set wholesale electricity rates. The CPUC requested that FERC issue a declaration that the CHP FIT program was not preempted by federal law.[481]

FERC determined in July 2010 that the CPUC was effectively setting the price at which electricity was sold by CHP facilities. FERC also determined that the program might be acceptable if it were set up in compliance with the Public Utilities Regulatory Policy Act (PURPA). PURPA requires utilities to purchase power from qualifying facilities at state-established rates that are no higher than the utilities' avoided costs.[482] FERC issued a clarifying order on October 21, 2010, where it made clear that states have wide latitude in establishing the level of avoided costs under PURPA and that a multi-tiered avoided cost rate structure is acceptable.

FERC clarified that the state may include in its avoided cost calculation the costs of transmission upgrades that would be avoided by the utility by purchasing power from local resources. These clarifications have the effect of allowing states to set higher rates for qualifying facilities. FERC also made clear that a state is free to establish a basis for providing additional compensation to favored resources through mechanisms that are outside of the avoided cost rate. One example is the creation of renewable energy credits that the generator can sell and that the utility must purchase.

There are other methods available, besides the establishment of avoided cost, for states to sidestep concerns over federal preemption of FIT programs. California can require the IOUs to purchase a specified amount of electricity from a governmental entity, at rates set by that entity, established for the purpose of encouraging the preferred generation resources. That entity would then purchase electricity from the favored resources at prices sufficient to encourage development of those resources. FERC does not have jurisdiction under the *Federal Power Act* over power sales by governmental entities that may be established by the states.[483]

The state may have to consider another approach to protect ratepayer interests if the CPUC finds itself institutionally constrained from establishing a FIT under SB 32, or under AB 1613, that is sufficient to finance and build projects. The FIT must achieve the same purpose for rooftop PV systems and small CHP that is achieved by SB 1036 for utility-scale RPS solar projects – "the establishment of expenditure limits that approximate the expected cost of building, owning, and operating eligible renewable energy resources." The FERC order validates the CPUC's authority to: 1) set FIT rates at the avoided cost to the utility, and 2) take a broad view of the cost elements that make up that avoided cost. However, it does not order that this authority be used.

The state has the authority to designate a government entity that: 1) sets FIT rates for distributed PV and CHP resources, 2) purchases the PV and CHP electricity at the set rates, and 3) requires each IOU to purchase a specific amount of electricity from these resources. FERC acknowledges that a state requirement that the IOUs purchase electricity from a state-owned corporation at specified rates would not be preempted by FERC's authority over wholesale power sales.

There is a recent precedent for this type of state action, taken in response to the 2000-2001 energy crisis. In 2001 the state entered into a large number of 10-year contracts with merchant generators at above market rates. Specific contracts were assigned to each IOU.[484]

An existing state agency with demonstrated contract negotiation expertise, such as the Department of General Services, is a potential candidate to carry-out this function. General Services administers the state's revolving loan program under the *Energy Efficient State Property Revolving Fund*.[485] General Services could serve as the state government entity that sets clean energy payment rates for rooftop PV and CHP, purchases the electricity at the set rates, and requires each IOU to purchase a specific amount of these resources.

This clean energy payment option should be considered if the FITs set by the CPUC for distributed generation continue to be set at levels that inhibit the development of these resources. The ZNE goals in BASE 2020 and in the *Energy Efficiency Strategic Plan* will be substantially more challenging to meet if the state does not have a fair FIT program in place for rooftop PV systems.

14.2 Cost of New Natural Gas-Fired Plants

The economic and strategic stakes at play in establishing an appropriate FIT tariff are high. Four natural gas-fired power plants are in the queue to be built in the Bay Area: Russell City Energy Center (600 MW), Oakley Generating Station (624 MW), Marsh Landing Generating Station (760 MW), and Mariposa Energy Center (200 MW).[486] Russell City and Oakley will operate as load following units, with expected capacity factors in the 60 to 80 percent range.[487] Marsh Landing and Mariposa will be peaking facilities, with expected actual capacity factors of less than 10 percent.[488]

These plants all have long-term power purchase agreements with PG&E. This is a total of about 2,200 MW of capacity. If built, these plants will have expected operational lifetimes of 40 to 50 years. The collective capital cost of these four plants will be about $2.3 billion in 2009 dollars.[489]

The cost of having these gas-fired plants constantly at hand if needed – to have the capacity available whether or not it is actually used – will be borne by PG&E ratepayers over the life of these contracts.[490] Any customer desiring to leave PG&E and build a CHP plant, for example, will have to pay departing load charges levied against customers who were in the PG&E system when these long-term contract commitments were made.

The capacity charges associated with these four gas-fired plants will be substantial. These capacity charges cover the fixed costs associated with the generation resource, including the capital cost, operating personnel, and insurance. The CPUC has determined that it is necessary for ratepayers to pay the fixed costs of new generation to assure that the generation gets built.[491]

The annual fixed costs of the four gas-fired plants will be approximately $600 million per year over a 20-year book life.[492]

This $600 million per year charge will divert limited resources from clean energy alternatives. $600 million per year would purchase over 300 MW per year of PV at 2010 prices, or over 3,000 MW of cumulative PV over the 2011 – 2020 period.[493]

14.3 Calculating What Distributed PV Is Worth

A representative avoided cost for a distributed PV system in PG&E service territory can be calculated using: 1) the MPR, adjusted to reflect a typical percent capacity factor for a combined cycle plant and adjusted for the time-of-delivery (TOD) of solar generation, and 2) the line losses and transmission and distribution (T&D) costs that are avoided when a local PV system displaces grid power.

Combined cycle units operate as intermediate-load plants in California. Capacity factor is a measure of actual annual electricity production compared to maximum possible output if the unit is operated every hour of the year at maximum output. Combined cycle units typically operate at capacity factors of 60 to 70 percent.[494] The fleet average capacity factor in 2008 was 65 percent.[495,496] However, the fleet average capacity factor in 2010 was 50 percent.[497]

Combined cycle units generally do not operate during off-peak, low demand periods. Low demand periods include midnight to 6 am most workdays as well as weekends. Lower-cost nuclear, large hydroelectric, coal plants, and non-solar renewable energy resources meet the need during these periods. The highest operating costs are associated with simple cycle peaking turbines and older conventional steam plants, ordinarily only used during peak demand hours.

The CPUC and the CEC have both developed estimates of the LCOE for a new 500 MW combined cycle plant. The CPUC derived its combined cycle installed cost estimate by looking at three projects that were either operational (Palomar, Cosumnes) or under construction (Colusa) at the time the 2009 MPR was developed.[498] The dates of the installed cost estimates for these projects are: Palomar –June 2004, Cosumnes – January 2006, and Colusa – February 2008. The 2009 MPR calculation assumes a January 2010 online date.

In contrast, the CEC used a non-project specific combined cycle pricing model to develop LCOE projections for 2009 and 2018 online dates.[499] The CEC also examined a range of capacity factors. LCOE projections were developed for capacity factors of 55 percent, 75 percent, and 90 percent for an unfired 500 MW combined cycle unit. LCOE projections were also developed for capacity factors of 50 percent, 70 percent, and 85 percent for a duct-fired 550 MW combined cycle unit.[500]

The CPUC currently assumes a hypothetical capacity factor of 92 percent for a combined cycle unit when calculating the MPR.[501] However, the CPUC uses a capacity factor of 65 percent when calculating the actual expected electricity production from California’s fleet of combined cycle plants.[502] As noted, the actual fleet average for California combined cycle plants in 2010 was 50 percent.[503] The effect of capacity factor on the LCOE for a new 500 MW combined cycle plant is shown in Table 14-2 using the CEC combined cycle LCOE estimates.[504] The effect of using the unrealistically high capacity factor of 92 percent in the MPR calculation is to make the MPR reference price artificially low.

Calculating the MPR based on a 65 percent capacity factor would be conservative based on typical capacity factors for operational combined cycle plants in California. Assuming a capacity factor of 65 percent, the MPR value is $134/MWh for an online date of 2009. This MPR value is projected by the CEC to rise to $183/MWh for an online date of 2018.

Table 14-2. Effect of Capacity Factor on LCOE from New Combined Cycle Plant

Capacity factor (%)	LCOE, 2009 ($/MWh)	LCOE, 2013/2014 ($/MWh)	LCOE, 2018 ($/MWh)
92	118	140	161
75	124	147	169
65	134	158	183
55	146	173	199

Note: CEC provides LCOE values for online dates of 2009 and 2018. The values included for 2013/2014 were calculated by Powers Engineering and are the average of the 2009 and 2018 values.

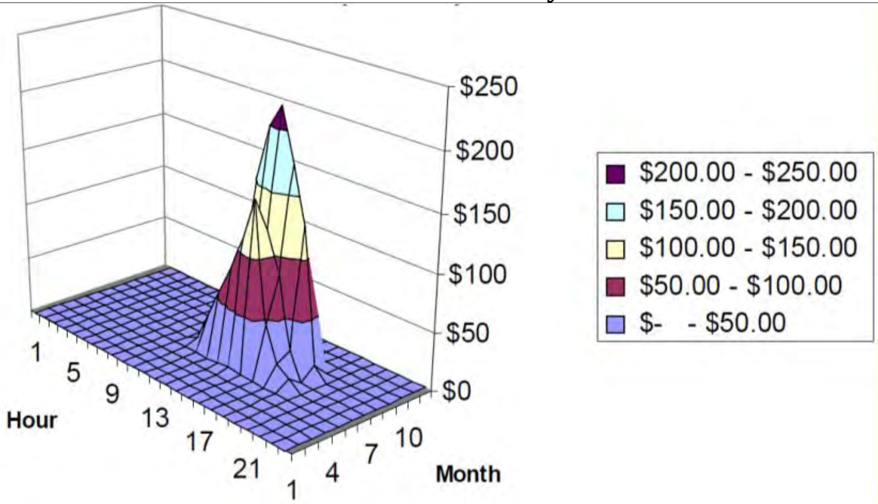
The mid-point between these two values is used in this report to estimate the MPR for an online date in the 2013 to 2014 timeframe. This MPR value is $158/MWh. The proposed start dates for 600 MW Russell City, 624 MW Oakley, 760 MW Marsh Landing, and 200 MW Mariposa are 2013, 2016, 2013, and 2012, respectively.[505] Given the average start-up date for the PG&E gas-fired capacity that could be substituted with distributed generation (DG) is 2013 to 2014, the appropriate MPR value is for a combined cycle unit that will be online in 2013 or 2014.

The generation of power at or near the point-of-use, whether it is solar PV or CHP, eliminates the transmission line losses that would occur if the electricity is imported from more distant sources to serve the same load. The value of the line losses avoided by use of DG in PG&E territory is approximately $10/MWh.[506]

The T&D system is sized to meet peak demand loads. Resources that reduce T&D loads on peak demand summer afternoons reduce wear-and-tear on the T&D system and delay the addition of new T&D infrastructure to meet peak demand load growth. The value of peak demand load reduction on summer afternoons in California is shown in Figure 14-2.

Fixed PV system output is a relatively good match for the high demand summer daytime load profile in California. *California Solar Initiative* fixed PV systems in PG&E service territory have a demonstrated availability during the 4 pm to 5 pm peak hour of more than 50 percent.[507] The peak availability of fixed PV is conservatively assumed to be 50 percent in BASE 2020.

Figure 14-2. Levelized Avoided T&D Cost by Month and Hour in $/kWh



The addition of local generation relieves load on the local distribution substation and the transmission line(s) serving that distribution substation. This effect is more pronounced in areas with inadequate transmission, or distribution substations approaching their capacity at times of peak demand. Energy and Environmental Economics, Inc. (E3), a CPUC contractor, developed the model adopted by the CPUC to determine the T&D avoided costs associated with energy efficiency programs. Ten separate PG&E divisions serve the nine-county Bay Area. The E3 model calculates energy efficiency avoided cost for each of these PG&E divisions.

The model calculates hour-by-hour avoided investment-related T&D costs. For this reason the model can be used to calculate the T&D costs avoided by a rooftop PV system with a representative output profile. The average solar PV T&D avoided cost of rooftop PV in Group 1 divisions is approximately $30/MWh. The average solar PV T&D avoided cost in Group 2 divisions is approximately $10/MWh. These T&D avoided costs are shown in Table 14-3.[508]

Table 14-3. Rooftop PV T&D Avoided Costs in PG&E Divisions in the Bay Area

PG&E Division	Rooftop PV T&D avoided cost ($/MWh)	Group
North Coast	27.84	1
North Bay	25.34	1
Sacramento	33.11	1
Diablo	30.67	1
Mission	37.57	1
San Jose	24.62	1
De Anza	32.35	1
Peninsula	11.16	2
San Francisco	9.02	2
East Bay	6.18	2

The average rooftop PV T&D avoided cost in Group 1 divisions is approximately $30/MWh, while the average rooftop PV T&D avoided cost in Group 2 divisions is approximately $10/MWh.

As noted, the GHG emissions component of the MPR is $15 per ton of CO_2. This converts to a cost addition of $6/MWh.[509]

The solar PV avoided cost calculation is:[510]

Avoided cost =	(CEC LCOE × TOD factor) + CO_2 adder + avoided line losses + avoided T&D	
Solar PV avoided cost [Group 1 area]	=	($158/MWh × 1.24) + $6/MWh + $10/MWh + $30/MWh
	=	$242/MWh
Solar PV avoided cost [Group 2 area]	=	($158/MWh × 1.24) + $6/MWh + $10/MWh + $10/MWh
	=	$222/MWh

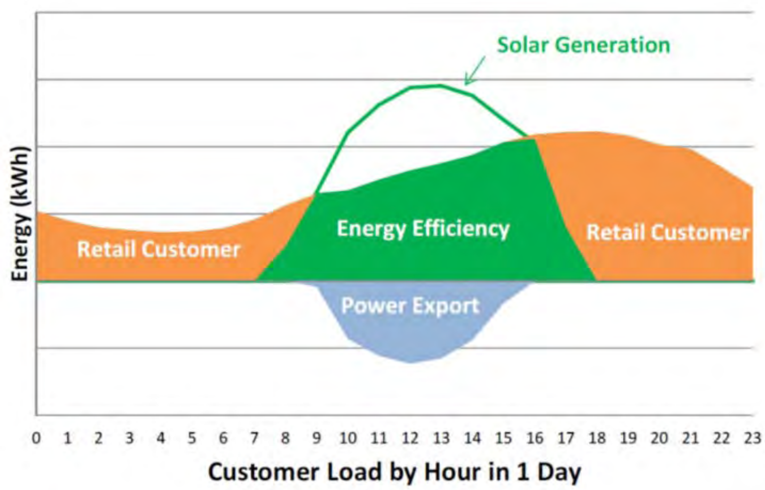
The solar PV value to PG&E is $242/MWh, or $0.242/kWh, in Group 1 areas and $222/kWh, or $0.222/kWh, in Group 2 areas. Any PV project or program with a tariff of less than $0.242/kWh in Group 1 areas in 2012, or $0.222/kWh in Group 2 areas, is a lower-cost resource than buying the same electricity from PG&E.

The CEC forecasts a 36 percent rise in the LCOE for a new combined cycle plant between 2009 and 2018.[511] In contrast, PV panel prices have declined by as much as two-thirds over the last three years.[512] Prices for PV are forecast to continue drop by 15 percent per year until 2015 due to oversupply and cheaper production.[513]

14.4 Net Metering

The overwhelming majority of non-RPS customer-owned PV in California is net-metered. The California *Million Solar Roofs* program will add 3,000 MW of primarily rooftop PV by the end of 2016 under net-metering. About 550 MW of this capacity will be added in the Bay Area. Net metering means the solar generators swap electricity with the utility at retail electricity rates. The solar generator can net meter up to 100 percent of the building's annual electricity demand. Net metering at retail electricity rates is a core financial assumption in advancing zero net energy building retrofits as cost-effective. An example of how net metering works is shown in Figure 14-3.

Figure 14-3. Three Phases of Operation of a Net-Metered PV System[514]



Currently PV installed under net metering does not count directly toward the utility's 33 percent RPS target. However, the green attribute of net-metered solar electricity, the renewable energy credit, may be purchased by PG&E to count toward the 33 percent RPS target as a result of CPUC regulatory action.[515] The tradable renewable energy credit (TREC) program was approved by the CPUC in January 2011.[516] These renewable energy credits are capped at $50 per MWh through 2013.

Equitable net metering must be preserved and existing net metering caps lifted for zero net energy programs like PACE to function to their potential. Net metered customers do not pay T&D charges. However, according to a December 2011 analysis of net metering in PG&E territory, this does not result in a shifting of these charges to customers without rooftop PV when all relevant costs and benefits of net-metered PV systems are evaluated together.[517]

The current cap on net-metered PV capacity, five percent of peak utility demand,[518] will become an obstacle in the near-term to zero net energy building retrofits if the five percent cap is not revised upward or removed entirely.

The net metering concept has expanded to include virtual net metering and community solar gardens. Virtual net metering is an option available for multi-tenant buildings as of July 2011.[519] It addresses the challenge of allocating rooftop PV output on a multi-tenant building to individual tenant electric meters. Virtual net metering provides an administrative mechanism that allows a single PV system to cover the electricity load of both common and tenant areas of a multi-tenant building. The electricity flows directly back onto the grid. The utility then allocates the kilowatt hours from the energy produced by the solar PV generating system to both the building owner and individual tenant utility accounts, based on a pre-arranged allocation agreement. The intent of virtual net metering is to assist low income multi-family residents to receive direct benefits from the PV system on the building.

Community solar gardens are variation of virtual net metering where the PV array is remote from electric meter that is credited with the PV generation. California legislation, SB 843, was introduced in 2011 that would authorize community solar gardens.[520] Community solar gardens allow renters and others who do not have an appropriate roof for PV to purchase or lease solar panels in a shared solar array located in the community. The renters would receive utility bill credits for the solar electricity as if the PV panels were located on their own rooftops.

14.4 Calculating What CHP Is Worth

The avoided cost to PG&E of CHP generation is somewhat different than that of PV. PV is a daytime resource with maximum output in the summer months. CHP is a round-the-clock baseload resource. For this reason, the TOD multiplier for CHP is 1.0. CHP can also be available continuously at rated capacity during the summer peak. However, because the CHP T&D avoided cost is divided over many more hours of operation than in the case of rooftop PV, the value of T&D avoided cost per MWh of CHP production is lower. In both Group 1 and Group 2 areas, the CHP T&D avoided cost is less than $10/MWh.[521] The default T&D avoided cost of CHP is assumed to be $10/MWh. Therefore the total CHP avoided cost is:

Total CHP avoided cost = $158/MWh × 1.0 + $10/MWh + $10/MWh = $178/MWh

14.5 Merit Order Benefits of Distributed Energy

PG&E receives electric power from a wide variety of sources, both within its service territory and throughout the West. The generation mix in the western U.S. consists of nuclear plants, coal plants, large and small hydroelectric plants, baseload biomass boiler plants, baseload geothermal plants, baseload CHP plants, load-following natural gas-fired combined cycle plants, peaking natural gas-fired combustion turbine and steam boiler plants, wind plants, and solar plants.

The real-time price of power in a competitive wholesale power market is set by the generation source with the highest fuel cost that successfully bids into the market.[522] In the late evening, the market price of power is set by the low-cost base load units, as the demand is low and all higher-cost units are offline. Medium cost load-following combined cycle units will set the market price during much of the day most of the year. High cost peaking plants will set the price of power on hot summer afternoons when all lower-cost resources are already online. All operators online in any given hour are paid at the rate of the highest-cost unit that is online in that hour. Therefore keeping the highest-cost peaking units offline has the effect of lowering the cost of electricity, at times substantially, for all users.

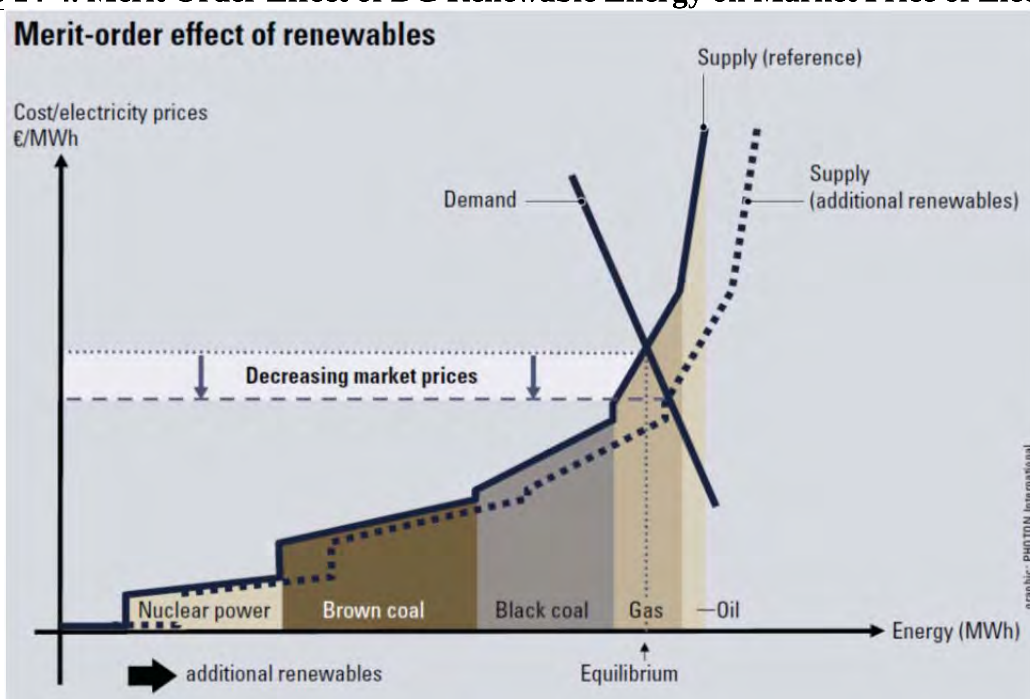
This phenomenon is shown in Figure 14-4 for the German power market on a hot summer afternoon. The reduction in German electricity market prices caused by renewable energy depressing market prices in 2009 is estimated at approximately $5 billion by the German government.[523] Germany produced approximately 16 percent, or 94,000 GWh, of its total electricity demand with renewable energy resources in 2009.[524,525] The $5 billion per year reduction in the market price of power is a $5 billion per year savings to German ratepayers.

Germany has an electricity market that is approximately twice the size of the California market at about 526,000 GWh per year of end user consumption.[526] Fall, winter, and spring market prices fluctuate between $30/MWh and $80/MWh, and summer prices fluctuate between $30 and $150/MWh.[527] The range of market prices for electricity in Germany is roughly comparable to the range in California.[528]

California consumed 287,000 GWh of electricity in 2008.[529] Estimates of 2009 renewable energy supply vary from 27,000 GWh to 37,000 GWh.[530] This translates into a renewable energy percentage of total California consumption of approximately 12 percent.[531] Scaling from the German experience with the merit order effect of renewable energy, the 12 percent renewable energy contribution to the California power market would depress electricity market prices by roughly $2 billion per year.[532] On a unit basis, this equals a price reduction of about $170 million per year per 1 percent increase in renewable energy percentage in the California electricity market.[533]

One percent of the California electricity market is 287,000 GWh per year × 0.01 = 2,870 GWh per year. The merit order effect would be achieved whether the distributed resource is renewable or natural gas-fired CHP. By way of example, a combination of 1,000 MW per year of new fixed solar PV and 150 MW of new CHP would add about 2,900 GWh per year of new DG resources. Assuming all of the projects are 1 MW in size, there would be 1,150 new projects each year.

Figure 14-4. Merit Order Effect of DG Renewable Energy on Market Price of Electricity[534]



The economic benefit to California ratepayers of the wholesale electricity market price depression effect would be approximately $150,000 per MW of new DG capacity installed per year.[535] The financing period for these generation projects is typically 20 years. The net present value of 20 years of electricity market price depression caused by these projects, in 2011 dollars, would be approximately $1.6 million per MW of installed capacity.[536]

To put this value in perspective, the net capital cost of a 1 MW_{ac} commercial rooftop PV array in California, assuming a $3.50/$W_{dc}$ gross installed cost, would be approximately $1.8 million with the 30 percent investment tax credit and accelerated depreciation.[537]

Major DG projects in the Bay Area have been stalled for a number of reasons. One such project, the proposed 50 MW CHP upgrade to the downtown San Francisco steam loop boiler plant, was identified in the *2002 Strategic Energy Plan* for San Francisco as a priority project but has yet to move forward.[538] The net present value of the economic benefit from electricity market price depression of this project would be in the range of $75 million based on the German experience. A major PG&E substation is located about one-half mile from the project site. Yet the project has not moved forward due to issues related to interconnection.

Renewable energy production in Germany is almost exclusively distributed renewable energy. Over four-fifths of solar capacity in Germany is on rooftops.[539] Wind farms average 9 MW.[540] Power flows from these local renewable energy systems are substantially reducing the need for market power purchases by German utilities and dampening wholesale electricity prices. In contrast, California IOUs are buying and developing substantial amounts of wind power far from California load centers. Wind generation in Oregon, Montana, and British Columbia will have less price reduction impact on the market price of power in California than local renewable energy.

14.6 Availability of Solar and Wind at Peak Hour

The construction of new generation and transmission in California is primarily justified by utilities on projections of rising peak load. Therefore it is necessary to understand what percentage of solar and wind capacity will be reliably available during peak demand to avoid excessive construction of conventional generation and transmission infrastructure.

Hot summer days are cloud-free or nearly cloud-free in the Bay Area. This results in maximum output from solar resources during peak demand periods.[541] In contrast, wind intensity is variable during summer mid-day and afternoon periods, good in Solano County and lower in Altamont Pass. As a result, assuming comparable amounts of solar and wind installed capacity, the solar resource would have the predominant market price depression effect on summer afternoons when market prices are highest.

The availability of distributed PV and wind resources during summer peak demand periods is shown in Table 14-4. The PV system output peak is mid-day, while the summer demand peak usually occurs in the mid-afternoon. By way of example, the one-hour peak demand event in PG&E territory in 2009, the source of the 54 percent peak capacity factor for fixed rooftop PV shown in Table 14-3, occurred between 4 pm and 5 pm on July 14, 2009.[542]

Table 14-4. Comparison of Peak Demand Capacity Factors for Solar and Wind

Technology	Peak capacity factor	Reference
Tracking solar PV	77	E3, *Inputs and Assumptions to 33% Renewables Portfolio Standard Implementation Analysis*, July 2009, Table 7, p. 12.
Fixed rooftop PV	54	Itron, *CPUC Self-Generation Incentive Program Ninth-Year Impact Evaluation - Final Report, prepared for PG&E*, June 2010, Table 5-14, p. 5-32.
Onshore wind	4	PG&E, *2006 Long-Term Procurement Plan - Volume 1*, December 11, 2006, p. IV-77.
	29	E3, *Inputs and Assumptions to 33% Renewables Portfolio Standard Implementation Analysis*, July 2009, Table 7, p. 12.

14.7 Concept of Clean Energy Payment

14.7.1 Overview

A clean energy payment, also known as a FIT, is a pre-established fixed long-term price for renewable energy or CHP. The use of fixed "standard offer" prices for renewable energy projects, the core of the FIT concept, is a proven model for assuring the financing of these projects. Thousands of MW of renewable wind, solar, and geothermal projects were built in California in the 1980s as a direct result of the standard offer contract structure that assured some profit for investors. This is the contract structure PG&E used with qualifying facilities.[543] Qualifying facilities are larger CHP plants that produce steam for industrial or commercial use and electric power primarily for export to the IOU, as well as biomass, geothermal, wind, and solar thermal projects.

FITs are set at a fixed price over a long term, generally 20 or 25 years. Price levels vary by technology, reflecting variation in technology costs. The challenge is setting a tariff that assures that system owner some profit while not over-paying. One mechanism used to avoid overpaying is to review payment levels frequently and to reduce levels over time to reflect lower costs.

14.7.2 German FIT Program

Germany has the most effective FIT structure in the world. Germany added 7,400 MW_{dc} of solar PV in 2010 and 7,500 MW_{dc} in 2011 for a cumulative total of about 25,000 MW_{dc} at the beginning of 2012.[544,545] Wind power capacity reached nearly 25,780 MW_{ac} by the end of 2009.[546] An additional 1,550 MW_{ac} of wind power was added in 2010.[547]

The rapid expansion of solar and wind power in Germany is also more economic than a business-as-usual expansion of natural gas- and coal-fired generation. According to the German Environmental Ministry's guideline scenario, wind energy will reach 108,000 GWh in 2020.[548] The installed capacity of solar PV will reach 53.8 GW in 2020.[549] This PV will generate 47,000 GWh of solar electricity in 2020.

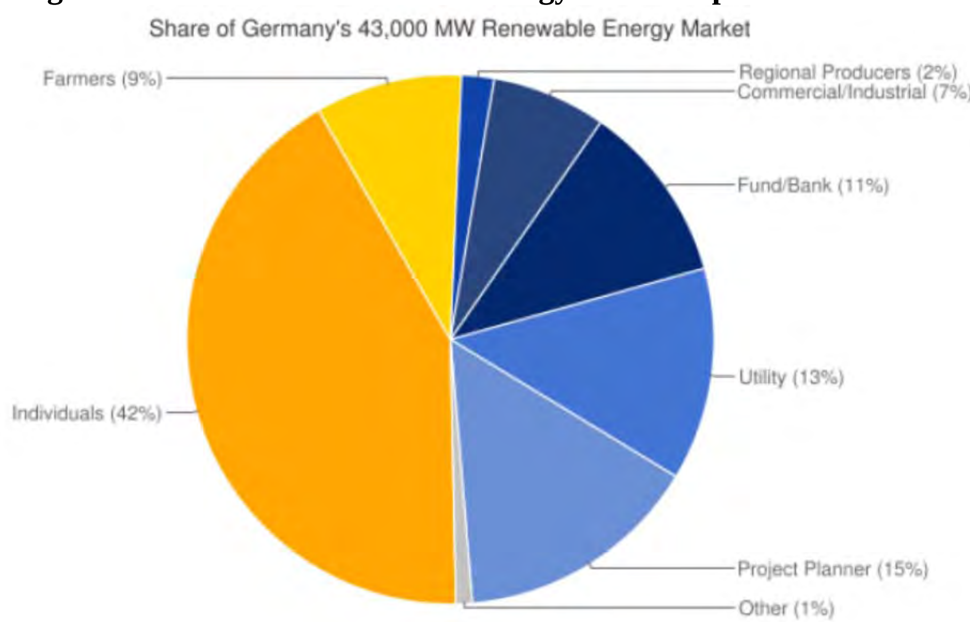
The German Institute for Economic Research electricity market model, based on these quantities of wind and solar electricity, projects an average inflation-adjusted electricity price of 49.3 €/MWh in 2020.[550] This corresponds to a real increase of 11 percent over the average German wholesale electricity price in 2010.

The German Institute for Economic Research also investigated a hypothetical scenario where renewable energy is not expanded beyond current levels. Instead, natural gas- and coal-fired generation is built. The net installed capacity of new conventional power plants is 12.1 GW higher than in the baseline scenario.[551] The smaller supply of renewable electricity leads to higher electricity prices in 2020.

The modeling of the conventional generation scenario predicts a wholesale price of 52.5 €/MWh in 2020, compared to the baseline wind and solar scenario price of 49.3 €/MWh. The baseline wind and solar scenario leads to a price reduction of 3.2 €/MWh in 2020 compared to the conventional generation scenario.[552] This is a 6 percent reduction compared to a conventional fossil generation build-out.

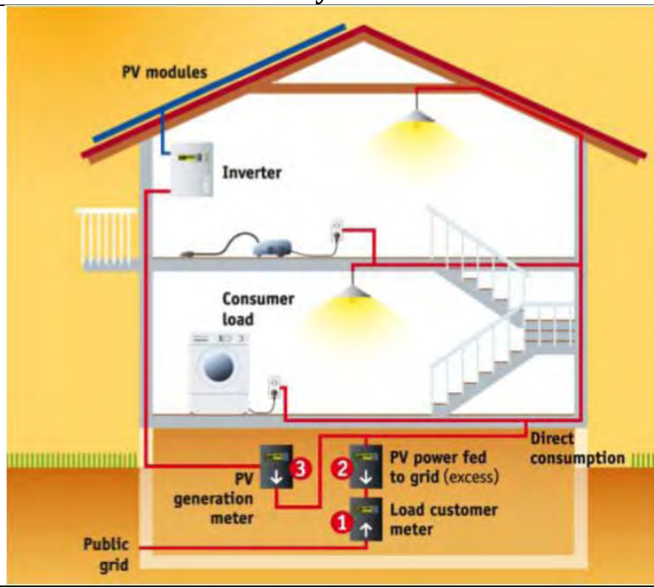
One hallmark of the German FIT is that ownership of renewable generation is highly dispersed. Approximately half of the renewable energy generation in Germany is owned by individuals. See Figure 14-5.[553] Critical components of the FIT, in addition to an adequate price, are that the utilities have an obligation to interconnect the generator and there are no caps on the quantity of renewable power that can utilize the FIT.

Figure 14-5. German Renewable Energy Ownership Distribution



Owners of PV arrays less than 500 kW now have the option under the German program to utilize some of the output onsite in net-metered configuration. These hybrid systems, both net-metered and FIT, have an additional meter to allow accurate tracking of on-site consumption and net export of PV electricity to the grid. The meter configuration is shown in Figure 14-6.

Figure 14-6. German Residential PV System that Uses Net-Metering and FIT[554]



14.7.3 Ontario FIT Program

The province of Ontario, Canada has implemented a FIT program with many of the characteristics of the successful German program. Ontario installed 143 MW_{ac} (168 MW_{dc}) of solar PV systems in 2010, second only to California in North America.[555] The FIT program was enabled by the *Green Energy and Green Economy Act of 2009*. The Ontario Power Authority (OPA) is responsible for implementing the program.[556]

A primary objective of the FIT program is to assist Ontario to phase-out coal-fired electricity generation by 2014. Additional goals include boosting economic activity, the development of renewable energy technologies, and the creation of new green industries and jobs.

A critical component of the Ontario FIT is a transparent interconnection procedure. The available capacity on all substations in the OPA system is listed on a public website. If sufficient T&D capacity is available at the proposed connection point for a specific project, the project developer is offered a FIT contract.[557]

When connection availability is insufficient, the OPA determines the T&D upgrades required and, in conjunction with other applications that require the same upgrades, assesses whether the upgrades are economically justifiable. Upgrades that are justifiable are included in T&D expansion plans. FIT contracts are offered once the upgrades receive required approvals and the OPA is reasonably certain that they will be completed by the commercial operation target dates in the affected applications.

The Ontario program also includes Canadian content provisions. Wind projects larger than 10 kW must include at least 50 percent domestic content starting in 2012. PV systems must include at least 60 percent domestic content starting in 2011.[558]

14.7.4 Financial Drivers Behind U.S. Renewable Energy Development

Renewable energy development in the U.S. is contingent on federal investment tax credits or production tax credits, and accelerated depreciation. This program has been essential in the U.S. for promoting solar and wind power. Historically it has been an "on again, off again" tax credit, subjecting the renewable energy industry to boom and bust cycles. This deficiency has been rectified to a degree as renewable energy tax credits are now available through 2016.[559] It also only applies to private commercial developers who can use tax credits. Government agencies and POUs like Alameda Municipal Power, City of Palo Alto Utilities, San Francisco Public Utilities Commission, Silicon Valley Power, and the Northern California Power Agency are ineligible.

14.7.5 Developing Effective Clean Energy Payments in California

The standard offer contracts pioneered in California in the 1980s were the driver behind California's world leadership in wind and solar generation capacity in the 1980s and 1990s. The standard offer payments were fixed over a sufficiently long time horizon to assure the financial viability of the renewable energy projects.

California legislation established FIT pilot programs in 2006 for renewable energy projects with capacities up to 1.5 MW in 2006 (AB 1969) and for CHP projects with capacities up to 20 MW in 2007 (AB 1613).

SB 32, passed into law in 2009, is an expansion of the AB 1969 FIT program. It authorizes the construction of up to 750 MW of solar PV, with individual project capacity up to 3 MW. The CPUC issued a ruling on January 27, 2011 requesting briefs to implement SB 32.[560] No decision on the structure of the SB 32 FIT had been issued as of February 2012.

In a separate program, the CPUC is implementing the renewable auction mechanism (RAM) to establish the price of distributed PV. The concept behind RAM is that PV project proposals will bid against each other and the low bidder will be awarded a contract. In concept this will lead to the lowest cost to the ratepayer. The CPUC approved the RAM program in December 2010.[561] Up to 1,000 MW of PV contracts will be awarded over two years.

RAM was conceived to avoid the perceived problem that FITs would be set at artificially high rates. The RAM program obligates developers to calculate the cost of their projects and then offer a bid high enough to generate a profit, yet low enough to win a contract.

Problems with FIT programs in Spain and Italy are cited in the December 2010 CPUC decision as the justification for substituting a conventional FIT with RAM.[562] The implication is that conventional FIT design inevitably results in over-paying and price shock to the ratepayer. Yet the decision approving the RAM program avoids mention of the successful FIT program in Germany. Germany has effective cost controls, re-evaluating FIT tariffs at six-month intervals, that have led to substantially lower PV installed costs in Germany than in California. There is also no mention in the RAM decision of the successful Ontario FIT program that is modeled on the German program. The Ontario FIT has led Ontario to be second only to California in PV installations in North America one year after the program began operating.[563]

There are a number of concerns with the RAM approach that would be eliminated by a well-designed FIT. The auction process is non-transparent and controlled by the IOUs. This same non-transparent framework is a core element of the heavily criticized RPS procurement process. A section header in the CEC's *2007 Integrated Energy Policy Report* effectively summarizes these criticisms: "RPS Program Structure: Need for Greater Transparency, Less Complexity, and Full Valuation of Renewable Energy." The lack of transparency in the RAM program creates the potential for gaming of the auction process. The uncertainty in the actual price hampers the ability of companies with multiple facilities to make strategic commitments to add PV in a methodical manner to all of its facilities.

The 1,000 MW of PV to be developed under the RAM program will be split proportionately among the state's three IOUs.[564] The program will result in approximately 420 MW of new solar PV development in PG&E territory.[565]

However, the December 2010 RAM decision was challenged by PG&E. The company stated in its rehearing request that:

> First, PG&E's RAM procurement obligation is not limited to procuring only those resources whose prices are at or below the Commission-determined market price referent (MPR), which violates the RPS statute's cost limitation provisions. Second, the Decision does not permit the IOUs to suspend their RAM programs if they achieve the 20 percent RPS target, which violates the RPS statute's clear directive that the IOUs cannot be required to procure greater than 20 percent renewables.[566]

The RPS mandate was increased to 33 percent with the passage of SB 2 (1X) in April 2011.[567] However, this challenge by PG&E is revealing. PG&E's reticence to pay more than the MPR in the RAM program is contradicted by recent PG&E contracts for large-scale solar power, where the company has voluntarily agreed to pay more than the MPR. In the case of these contracts, the CPUC has given PG&E approval to pass on all costs above the MPR to ratepayers. For example, the CPUC approval of the contract between PG&E and the 250 MW Genesis solar thermal project states:

> Based on a 2014 guaranteed commercial online date for the Project, the 25-year PPA exceeds the 2008 MPR and therefore has above-market costs associated with it. . . Therefore, PG&E will voluntarily incur the above-MPR costs of the PPA. . . Payments made by PG&E under the Genesis Solar, LLC power purchase agreement are fully recoverable in rates over the life of the agreement.[568]

14.8 Solar PV FIT - Lower Than PG&E's Avoided Cost

In July 2010 UCLA/LABC developed a proposed FIT for use in LADWP service territory. The tariff rates are structured to make the development of 3,300 MW of the City of Los Angeles estimated 5,536 MW of rooftop PV potential economically feasible over ten years. The study also estimates that 12,500 MW of 19,113 MW of a Los Angeles County rooftop PV potential could be economic to develop over ten years with the proposed FIT rates.

UCLA/LABC proposed a program cap of 600 MW. The 600 MW is allocated across three proposed tariff categories as shown in Table 14-5. This allocation results in a 2010 composite tariff for the program of $0.22/kWh.

Table 14-5. PV FIT Categories, First Year Tariff, and Capacity Allocation

Category	Eligible systems	Typical participants	2010 tariff ($/kWh)	Capacity allocation (MW)
Small rooftops	< 50 kW	Single family homes, small office, retail, apartments	0.34	100
Large rooftops	≥ 50 kW	Warehouses, distribution facilities, light manufacturing, industrial	0.22	300
Large ground-mounts	Commercial ground-mounted	Large ground-mounted, installed for optimum efficiency	0.16	200
Composite tariff			0.22	

The UCLA/LABC study incorporated a tariff decline rate of 5 percent per year as shown in Table 14-6. The composite program tariff assumes the same relative capacity allocation shown in Table 14-5 throughout the 10-year duration of the program.

Table 14-6. PV FIT Decline Rate Over 10 Years of Program

Category	Tariff per kWh for a new contract in program year ($/kWh)									
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Small rooftops	0.34	0.32	0.31	0.29	0.28	0.26	0.25	0.24	0.23	0.21
Large rooftops	0.22	0.21	0.20	0.19	0.18	0.17	0.16	0.15	0.15	0.14
Ground-mount	0.16	0.15	0.14	0.14	0.13	0.12	0.12	0.11	0.10	0.10
Composite (in 2010 dollars)	0.22	0.21	0.20	0.19	0.18	0.17	0.16	0.15	0.15	0.14

The FITs shown in Tables 14-5 and 14-6 are sufficient to facilitate rapid growth in distributed PV deployment in California.[569] The 2012 composite program tariff of $0.20/kWh is slightly less than the projected avoided cost of a new combined cycle power plant online in 2013 or 2014 (Marsh Landing) or 2016 (Oakley). The PV program tariffs steadily decline over time. In contrast, the avoided cost of a new combined cycle plant steadily rises.[570]

The FITs shown in Tables 14-5 and 14-6 assume the availability of the federal 30 percent investment tax credit for residential PV projects, and the federal 30 percent investment tax credit and accelerated depreciation for commercial projects. The effect of these tax benefits on the net capital cost of a commercial rooftop PV system is detailed in Appendix G. These tax benefits will expire in 2016 unless extended in federal legislation. The tariffs for 2017 through 2019 will have to be increased if these tax benefits are not extended beyond 2016. A reasonable guideline for resetting the tariff ceiling would be that the composite value of the FIT could not exceed the avoided cost to the IOU in the year the tax benefits expire.[571]

Adding two additional categories to the proposed UCLA/LABC FIT structure would lower overall program cost. Table 14-7 presents a revised BASE 2020 tariff structure with five categories. The objective of the revised tariff structure is to lower overall program costs. The relative PV capacity allocations would remain the same as those shown in Table 14-4. However, the large rooftop category in the UCLA/LABC FIT is expanded into three commercial rooftop categories. An even split of capacity is assumed across these three categories. The 2012 tariffs in Table 14-6 reflect the cost of PV in California as of late 2011. The calculation to determine the composite tariff is:

$$\text{Composite 2012 tariff} = [\$0.25/\text{kWh} \times (100/600)] + [(\$0.15/\text{kWh} + \$0.14/\text{kWh} + \$0.13/\text{kWh})/3 \times (300/600)] + [(\$0.12/\text{kWh}) \times (200/600)]$$

$$= \$0.15/\text{kWh}$$

Table 14-7. Revised PV FIT to Reduce Overall Program Cost

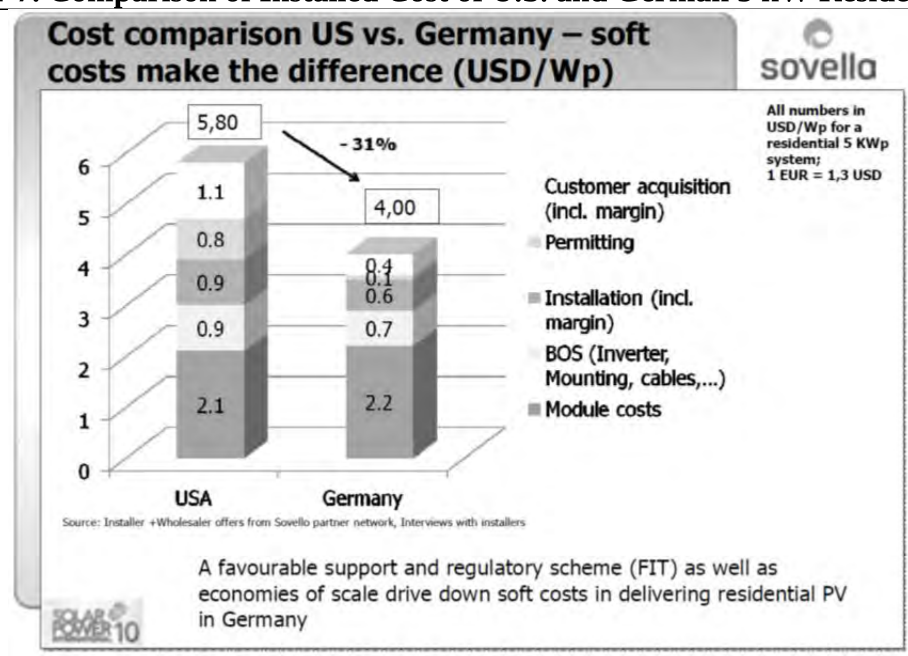
Category	Tariff per kWh for a new contract in program year ($/kWh)								
	2012	2013	2014	2015	2016	2017	2018	2019	2020
Residential, <10 kW	0.25	0.24	0.23	0.21	0.20	0.19	0.18	0.17	0.16
Small commercial, 10 – 50 kW	0.15	0.14	0.14	0.13	0.12	0.12	0.11	0.10	0.10
Medium commercial, >50 – 200 kW	0.14	0.13	0.13	0.12	0.11	0.11	0.10	0.10	0.09
Large commercial, >200 kW	0.13	0.12	0.12	0.11	0.11	0.10	0.10	0.09	0.08
Ground-mount, commercial	0.12	0.11	0.11	0.10	0.10	0.09	0.09	0.08	0.07
Composite (in 2012 dollars)	0.15	0.14	0.14	0.13	0.12	0.12	0.11	0.10	0.09

Note: The term “residential” includes rooftop or ground-mount installations at a single family residence. The term “commercial” includes rooftops, parking structures, and parking lots. The term “ground-mount” applies to installations on open land. Residential < 10 kW assumes residential at $\$5/W_{dc}$ in 2012 with 30% ITC. Small commercial pricing assumes a capital cost of $\$4/W_{dc}$ in 2012 with 30% ITC and accelerated depreciation. Incremental 5 to 10 percent cost reductions are assumed as commercial array size increases.

The practical viability of the FIT tariff shown in Table 14-7 was corroborated by: 1) reviewing current competitive pricing for principal PV market segments, and 2) communicating with PV system installers regarding the adequacy of the pricing. In addition, the Palo Alto public utility, CPAU, recently announced a FIT program for commercial rooftop PV 100 kW or greater with a 2012 tariff price of $0.14/kWh.[572] A 2012 tariff price of $0.14/kWh for 100 kW rooftop PV systems is consistent with the FIT tariff schedule in Table 14-7. The proposed PV tariff assumes a 2012 residential PV system gross capital cost of $\$5/W_{dc}$. This is consistent with retail residential 2010 PV pricing in some U.S. markets.[573] The $\$5/W_{dc}$ assumption is higher than residential PV pricing in some group-buy PV programs, with offer prices as low as $\$4.67/W_{dc}$[574] and $\$4.40/W_{dc}$.[575]

German residential PV systems, with the same PV panel and hardware costs as U.S. systems, are installed for about two-thirds the cost of a typical U.S. installation. The installed cost of a representative 5 kW_{dc} residential PV system in Germany was about $\$4/W_{dc}$ in late 2010, as shown in Figure 14-7. This cost has declined to about $\$3/W_{dc}$ on average in late 2011. The same PV system in the U.S. would typically cost \$5 to $6/W_{dc}$. The difference in price is primarily related to higher U.S. costs of installation, permitting, marketing, and higher U.S. profit margins. The higher volume of residential PV sales in Germany produce economies of scale that drive down costs.

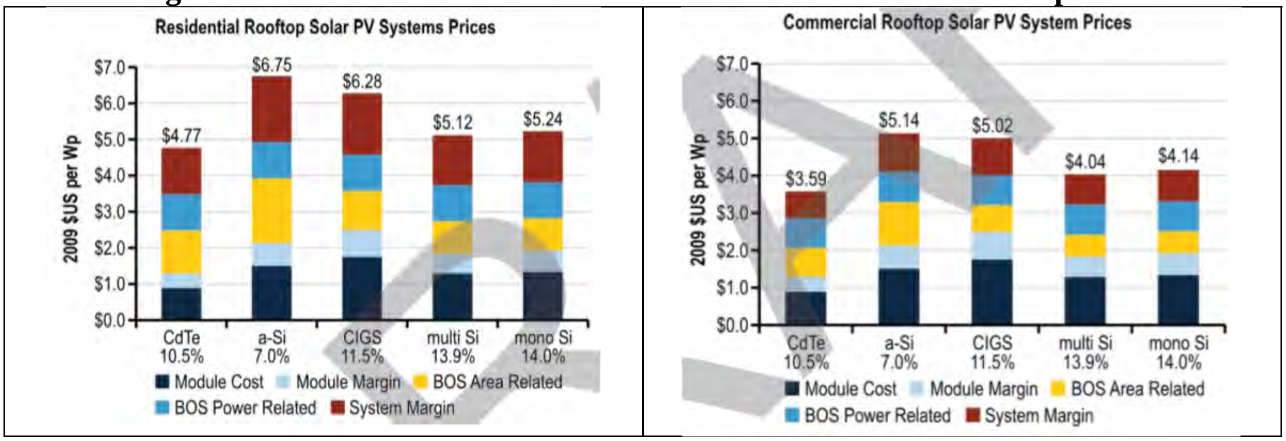
Figure 14-7. Comparison of Installed Cost of U.S. and German 5 kW Residential PV[576]



One reason for the lower installed cost of German PV systems is standardized permitting. The Department of Energy is funding the development of a scalable standard template for solar PV permitting, inspection and interconnection, by states, utilities and local jurisdictions. The Bay Area will be a pilot site for establishing a regional standardized solar permitting process under the Department of Energy program.[577]

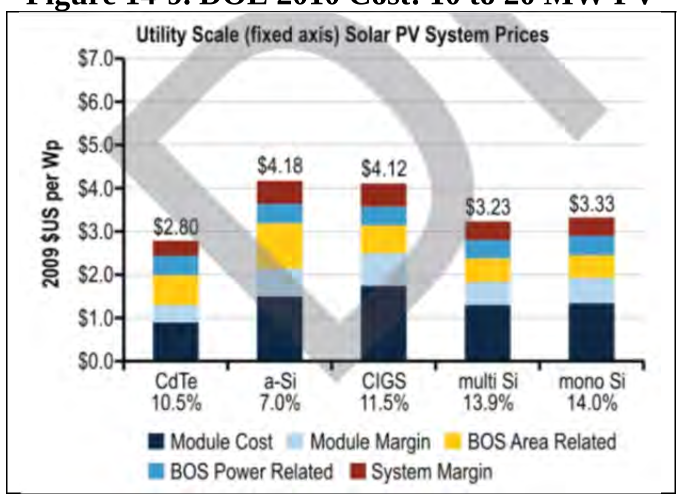
Figures 14-8 shows the best-case early 2010 PV pricing identified by DOE for residential and commercial rooftop PV. The commercial rooftop PV pricing in Figure 14-8 is consistent with publicly-available cost information for the same period. Southern California Edison received approval from the CPUC to construct 500 MW of 1 to 2 MW warehouse rooftop PV arrays in June 2009.[578] The CPUC established a capital cost price cap in the SCE approval of $3.50/W_{dc}$.

Figure 14-8. DOE 2010 Cost of Residential and Commercial Rooftop PV[579]



Figures 14-9 shows best-case early 2010 PV pricing identified by DOE for "utility-scale" ground-mounted PV systems. DOE identifies utility-scale as ranging from a few MW to hundreds of MW.[580] This pricing is consistent with the PV capital cost range shown in Table 6-1 for fixed PV systems with a LCOE of less than $140/MWh at ideal sites.

Figure 14-9. DOE 2010 Cost: 10 to 20 MW PV

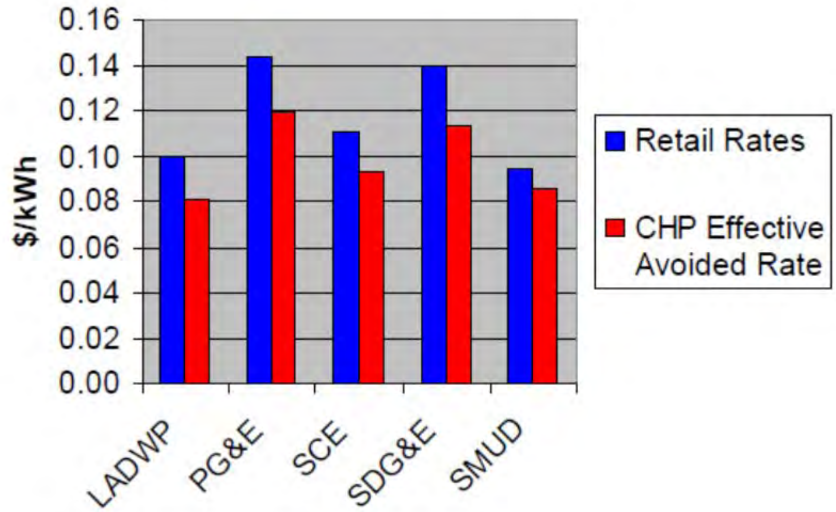


14.9 CHP FIT - Lower Than PG&E's Avoided Cost

The average avoided cost of CHP to PG&E is just under $0.18/kWh. This means that the cost to PG&E to replace electricity that would otherwise be generated by a CHP plant is in the range of $0.18/kWh.

The LCOE for a typical small natural-gas fired CHP plant in California powered by an internal combustion engine or gas turbine is shown in Figure 14-10.[581] The LCOE of CHP in PG&E territory is in the range of $0.12/kWh. The retail rate the customer would be charged for electricity if the CHP plant did not exist was over $0.14/kWh in 2009.[582] The $0.12/kWh LCOE for the CHP plant includes departing load surcharges and the impacts of demand charges incurred when the CHP system goes down during peak hours.[583]

Figure 14-10. California Utility Retail Rates and 50 to 500 kW CHP Cost of Electricity



14.10 Fuel Cell CHP

SGIP incentives are available for fuel cells, energy storage, and small wind turbines. These incentive payments are shown in Table 14-8.[584] As a result, even though fuel cell CHP projects are substantially more capital intensive than engine or gas turbine CHP projects, the net LCOE for a fuel cell CHP plant can be at or below the LCOE from a comparable engine or gas turbine CHP plant.

Table 14-8. SGIP Incentive Payments for Fuel Cells, Energy Storage, and Wind Turbines

Technology	Energy payment ($/kW)	System Size		Max. size for full incentive (MW)
		minimum (kW)	maximum (MW)	
Wind turbine	1,500	30	5	1
Fuel cell, renewable fuel	4,500	30	5	1
Fuel cell, non-renewable fuel	2,500	none	5	1
Energy storage	2,000	none	5	1

Note: 2010 incentive rate was capped at 3 MW. 0 – 1 MW 100%; >1 MW – 2 MW 50%; >2 MW – 3 MW 25%.

An example of fuel cell economics in California is the fuel cell CHP plant at UC San Diego described in Chapter 13. The project receives the maximum SGIP fuel cell incentive because it uses, biogas, a renewable fuel. Biogas from the nearby San Diego wastewater treatment facility will be piped to UC San Diego for use in the fuel cell. The cost of electricity to UC San Diego will be in the range of $0.12/kWh under a long-term contract between UC San Diego and the turnkey supplier of the fuel cell system. The project is expected to save UC San Diego and San Diego a combined $2 million over the life of the 10-year power purchase agreement relative to retail electricity rates.[585,586]

The UC San Diego project uses a dedicated pipeline for the biogas because the relatively low gas quality prevents injection of the biogas into the utility natural gas pipeline system. However biogas can also be upgraded to biomethane, as discussed in Chapter 13, to allow injection into the utility pipeline network. This is one option available to convert any CHP plant in the Bay Area to a renewable fuel without onsite modifications.

Biomethane is more costly than natural gas, with an estimated production cost of $12/MMBtu compared to a current natural gas cost in the range of $4 to $5/MMBtu.[587] However, use of biomethane eliminates the need to build a dedicated biogas pipeline, as was done for the UC San Diego fuel cell project, or generate electricity at the point where the biogas is produced. The combustion of biomethane in a CHP plant puts to productive use a fuel that is otherwise flared or vented.

The CPUC proposed a complex pricing format for new CHP in its December 2010 settlement agreement decision with CHP operators.[588] A stated intent in the agreement is to facilitate the *AB 32 Scoping Plan* objective of adding 4,000 MW of new CHP by 2020.[589] However, the settlement agreement imposes the same IOU RPS procurement procedures on new CHP procurement. These procedures have contributed to slow progress on RPS procurement.[590] The IOUs will issue a request for offers for CHP projects and select projects based on some combination of least cost – best fit criteria. If the pricing of proposed projects is above the adopted market index pricing formula, the IOUs can use pricing as a reason to reject the project, and as an acceptable justification for failing to meet targets for new CHP capacity.

14.11 Conclusions and Recommendations

14.11.1 Conclusions

- The merit order effect of increased DG in the electricity supply mix reduces the wholesale cost of power to all customers. The merit order effect of DG in Germany, an electricity market two times the size of the California electricity market, reduced the wholesale electricity price to German customers by approximately $5 billion in 2009. The merit order effect of increased DG supply on wholesale electricity prices has not yet been quantified for the California power market.

- The RAM approach PV pricing is inferior to a well-designed, fixed clean energy payment structure due to the lack of transparency in the current program design, potential for gaming, and the inherent weakness of an auction mechanism in providing the investment security necessary for rapid and large-scale deployment of distributed PV systems.

- Equitable net metering must be preserved and existing net metering caps lifted for zero net energy programs like PACE to function to their potential.

- The renewable energy credit component of net-metered solar electricity may be purchased by PG&E to count toward the 33 percent RPS target.

- The cost to PG&E to provide electricity that would otherwise be provided by a PV system ranges from $0.22 to $0.24/kWh. A PV fixed payment of $0.22/kWh or less would meet the requirement in SB 32 that "ratepayers that do not receive service pursuant to the (FIT) tariff are indifferent to whether other ratepayers receive service pursuant to the tariff."

- The cost to PG&E to provide electricity that would otherwise be provided by a CHP is approximately $0.18/kWh.

- The current CHP LCOE in the Bay Area is about $0.12/kWh. A CHP fixed payment at or above this price level would be sufficient to spur a rapid increase in new CHP capacity in the Bay Area.

- Successful clean energy payment programs in Germany and Ontario require prompt interconnection by the utility upon receipt of an interconnection application.

- The merit order benefits of DG to all IOU customers, at $1.6 million per MW of new DG capacity based on German data, are so large that all DG interconnection costs should be borne by PG&E for DG systems. This would eliminate the most common reason that DG projects of all types fail to move forward – economic and technical interconnection obstacles.

- RPS contract terms are established at pricing designed to assure these projects can be financed and built. To date, clean energy payment programs for rooftop and smaller-scale PV projects up to 3 MW have been set at the MPR, a price point that has historically been too low to get these projects financed and built.

- The payment rate established by the CPUC for surplus solar electricity generated by net-metered rooftop PV systems, at approximately $0.04/kWh in PG&E territory, is one-fourth to one-fifth the contract price approved by the CPUC for selected 250 MW utility-scale solar thermal and solar PV projects.

14.11.2 Recommendations

- The 5 percent net metering cap should be eliminated.

- PG&E should be required by the CPUC to purchase renewable energy credits offered for sale by net-metered PV system owners.

- A PV clean energy payment (FIT) program should be established with a 2012 composite tariff of $0.15/kWh, declining to $0.09/kWh in 2020. The decline rate should be re-evaluated every six months to assure it reflects market conditions.

- The CHP FIT should be set initially at a rate incrementally above $0.12/kWh.

- The CEC should conduct an evaluation of the merit order effect of ever-increasing levels of DG in California on the wholesale electricity market price. The results of this evaluation would serve as the basis for shifting all DG interconnection costs to PG&E.

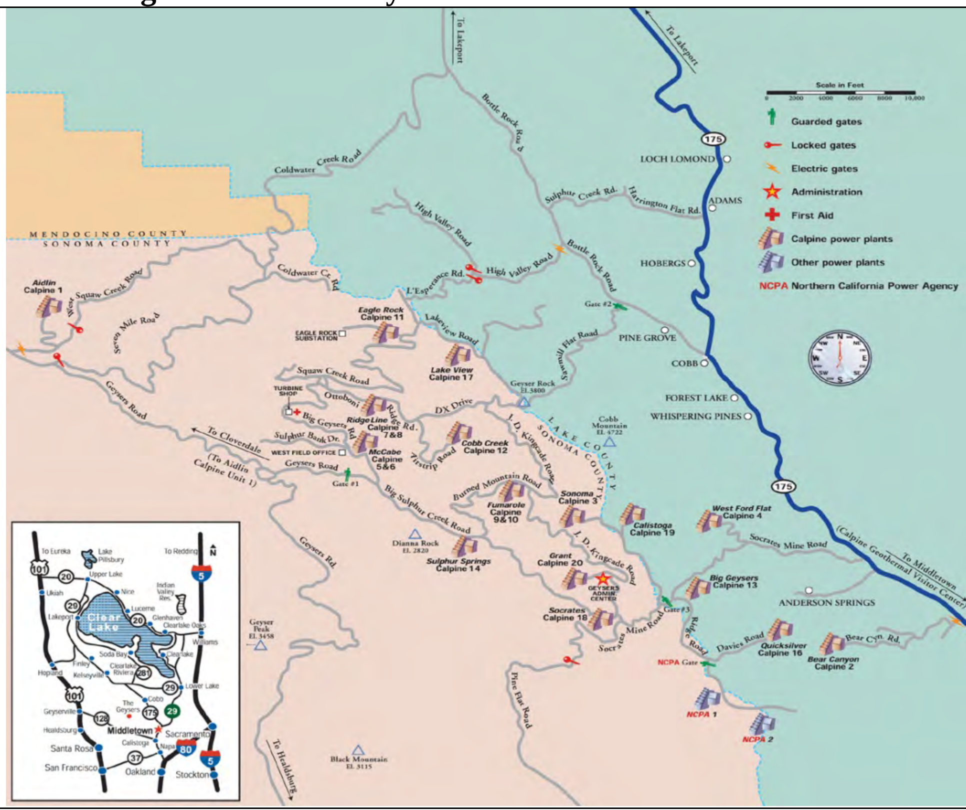
- The CEC should evaluate the avoided cost of distributed PV and CHP, using the CEC's modeled cost of new combined cycle plant cost-of-energy, and a realistic capacity factor of between 50 and 65 percent, in the analysis. The purpose of this evaluation would be to corroborate that the PV and CHP FIT tariffs proposed in BASE 2020 would reduce electricity costs for all PG&E ratepayers relative to business-as-usual.

- If the CPUC is institutionally constrained from setting clean energy payment rates for rooftop PV that are sufficient to get these projects financed and built, the state should mandate a clean energy payment program under a state agency with demonstrated contract management experience, such as the Department of General Services. Rates would be set at or below the IOU avoided cost. The IOUs would be required to purchase local PV resources at a rate sufficient to assure the 2020 rooftop PV targets in the *Energy Efficiency Strategic Plan* and BASE 2020 are met. This same recommendation also applies to distributed CHP projects up to 20 MW.

15. The Geysers Geothermal Power

An advantage of geothermal power is that it is a round-the-clock resource. The Bay Area has one geothermal production area – The Geysers in northeast Sonoma County. The Geysers has produced commercial geothermal power continuously since the early 1960s. Present generation is around 900 MW from eighteen geothermal plants owned by three operating companies: Calpine Corporation, Northern California Power Authority (NCPA), and U.S. Renewables.[591] The location of the geothermal plants in The Geysers is shown in Figure 15-1.

Figure 15-1. The Geysers Geothermal Resource Area[592]



Calpine owns and operates fifteen power plants at The Geysers with a net generating capacity of about 725 MW. This is sufficient to power 725,000 homes, or a city the size of San Francisco.[593] The output from this capacity is sold to PG&E and SCE.[594] The NCPA operates two geothermal plants at The Geysers with a net generating capacity of approximately 116 MW.[595] A portion of the output of the NCPA geothermal plants is sold to POUs in the Bay Area. U.S. Renewables owns one 55 MW geothermal plant at The Geysers.[596] Output from this plant is sold to PG&E under long-term contract.

Ram Power Corporation (formerly Western GeoPower) is developing a 25 MW plant at The Geysers. Output from this plant will be sold to NCPA under a 20-year power purchase agreement.[597] It is expected that the project will be completed by 2013 in order to qualify for the federal investment tax credit or production tax credit. The project will have access to an existing transmission line with no upgrades required.[598]

15.1 Evolution of The Geysers

The Geysers produced the first commercial geothermal electricity in the U.S. in 1960 at PG&E's 11 MW Unit No. 1 power plant. The Geysers went on to become the world's largest commercial geothermal field by the mid-1980s, with close to 20 power plants, nearly 2,000 MW of installed capacity, covering 30 square miles.

The NCPA built two 110 MW power plants in the southeast corner of The Geysers during this rapid growth phase. In January 1983, NCPA commissioned twin turbine generators at its 110 MW Plant No. 1, the first publicly-owned geothermal power facility to operate at The Geysers. Plant No. 1 is shown in Figure 15-2. In 1985, NCPA bought the geothermal wells, field production facilities and all rights for future development.[599]

Figure 15-2. NCPA Plant No. 1

Steam lines along road leading to NCPA Unit No. 1 at The Geysers. Photo: Ted J. Clutter.

Geothermal steam flow from production wells at The Geysers dropped precipitously in the late-1980s. Geologic investigations showed The Geysers reservoir was not recharging with surface water as quickly as believed. A nearly impervious carbonate cap beneath a layer of low permeability rock allowed little new water to percolate into the reservoir. Operators responded by closing inefficient power plants and throttling back others. Geysers geothermal plant operators were reinjecting only about 20 percent of the fluid being extracted back to the geothermal reservoir. The remainder was lost as evaporation in plant cooling towers.[600]

Injection from improved condensed steam collection and rainwater ponds raised replacement to the reservoir from around 20 percent to 33 percent by 1988. More water had to be found to reduce reservoir losses further. The problem was addressed by injected treated wastewater into the geothermal formation.[601]

Aging infrastructure and rapid population growth were overwhelming the Lake County Sanitation District's wastewater systems during the 1980s. A study in the early 1990s determined that injection of treated wastewater into The Geysers geothermal formation would help sustain the resource and avoid the need to upgrade Lake County Sanitation District's water treatment systems.[602]

The Southeast Geysers Effluent Project Pipeline, built from Clear Lake, California to The Geysers, started delivering secondary treated wastewater to injection wells in September 1997. The 26-mile-long, $45 million pipeline delivers around 8 million gallons a day of treated wastewater to the southeastern portion of The Geysers geothermal field.[603]

The treated wastewater injection has reduced reservoir decline to 3 to 4 percent per year. In the case of the NCPA geothermal plants, the pipeline provides 55 percent of the fluid NCPA injects back to The Geysers reservoir. NCPA now replaces 96 percent of fluid extracted from the reservoir each year. However, geothermal plants at The Geysers operate at production rates substantially lower than design capacity. Current production from the NCPA geothermal plants is only half of nameplate capacity of 220 MW.[604]

Calpine launched a multi-year $200 million program in 2007 to increase geothermal production at The Geysers by up to 80 MW.[605] The project involves rebuilding eight older steam turbines.

15.2 Micro-Earthquakes at The Geysers

Geothermal production at The Geysers does cause micro-earthquakes as pressures fluctuate within the deep geothermal formations. The U.S. Geological Survey recorded 1,007 seismic events at The Geysers in 2009. No major structural damage has been caused by micro-earthquakes at The Geysers to date. Geothermal operators work with the local community to address the nuisance that micro-earthquakes cause. Operators have established payments for repairs to cracked sidewalks, siding, chimneys and windows.[606]

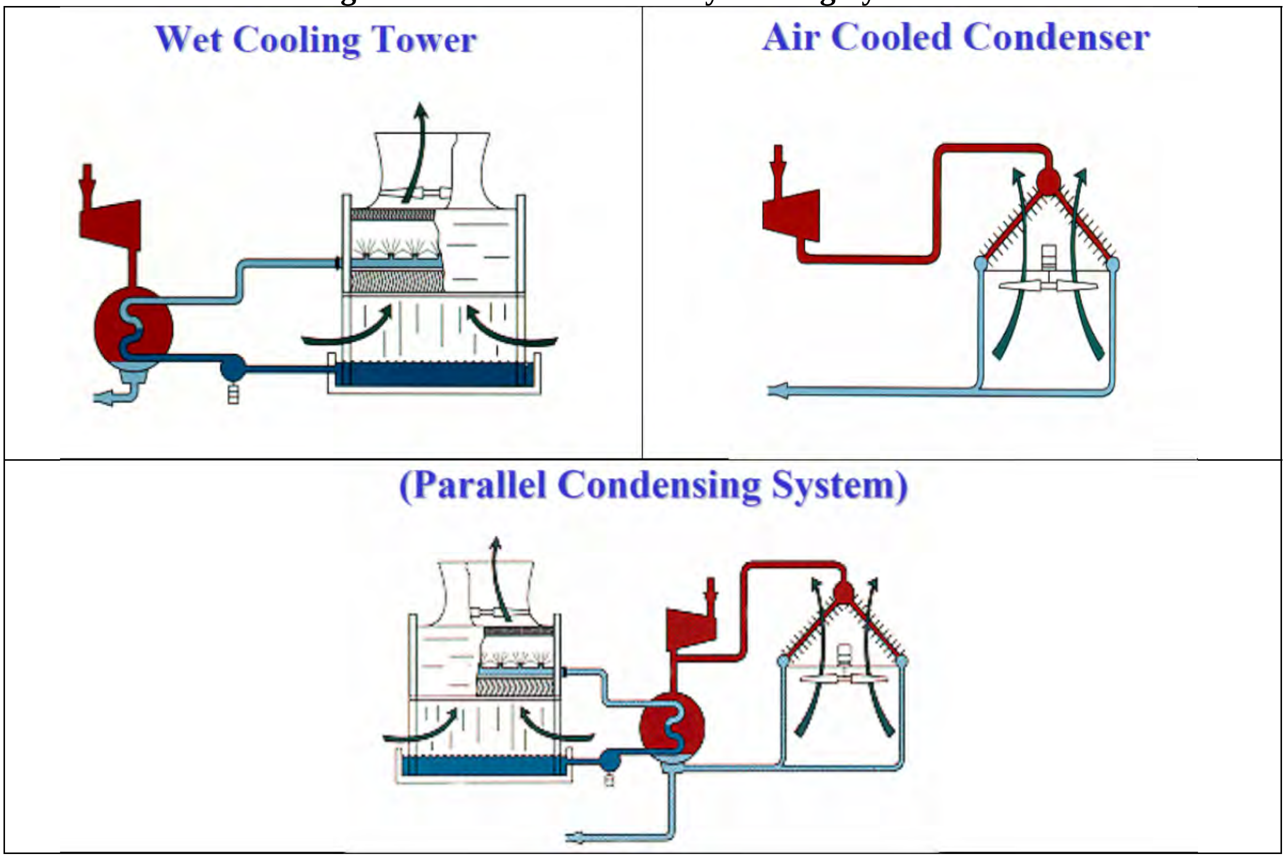
15.3 Achieving Sustainable Operation of The Geysers

Geothermal plants at The Geysers consume large volumes of water. This water is primarily lost to evaporation in the cooling towers. Much of the water used in the cooling tower is condensed geothermal reservoir fluid. This is geothermal fluid that does not get recycled back into the geothermal reservoir to maintain reservoir pressure.

There is no state policy to assure the long-term viability of geothermal resources. As a result, private geothermal developers have built plants with relatively low capital cost wet cooling, even though the evaporative water loss from the cooling tower depletes the geothermal resource over time. The proposed 25 MW Ram Power geothermal project at The Geysers is a case in point. The project will use a wet cooling tower. Currently geothermal developers have no incentive or requirement to incorporate parallel wet-dry cooling or dry cooling into new or existing plants at The Geysers to minimize consumptive water use.

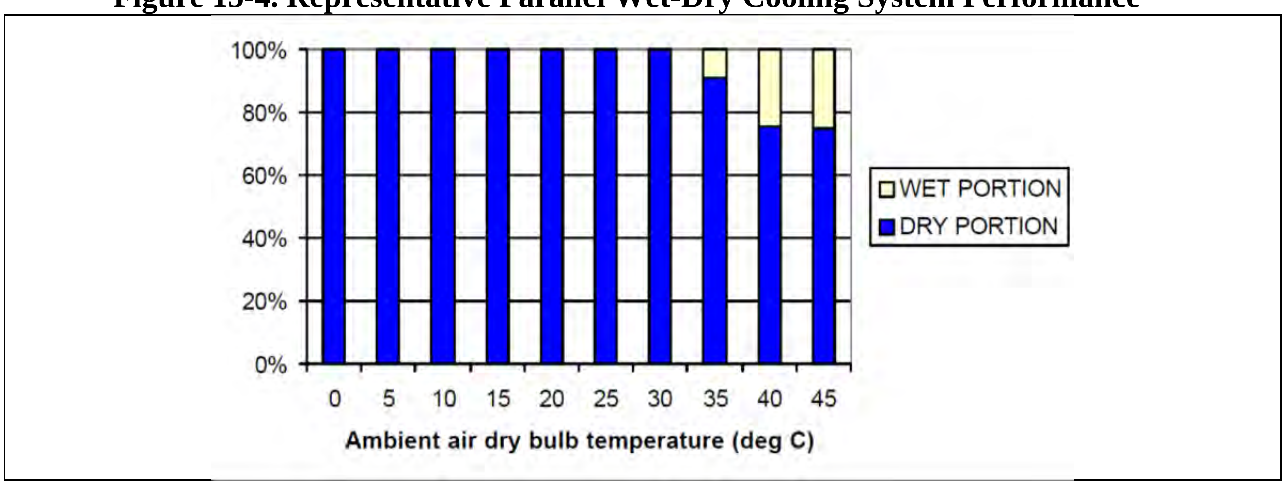
This issue can be addressed technically by retrofitting existing geothermal plants at The Geysers with parallel wet-dry cooling systems to substantially reduce cooling tower water consumption. Parallel wet-dry cooling systems have been in use on power plants since the mid-1990s. Retrofitting a dry cooling system, known as an air-cooled condenser, onto a plant equipped with a wet cooling tower is relatively straightforward. A schematic of a parallel wet-dry cooling system is shown in Figure 153. New geothermal plants would be built with dry cooling systems to reduce plant water consumption by up to 98 percent compared to the same plant equipped with a wet cooling tower.

Figure 15-3. Parallel Wet-Dry Cooling System[607]



Parallel wet-dry cooling systems can reduce consumptive water use relative to a wet cooling tower system by up to 90 percent. Figure 15-4 shows a representative parallel wet-dry cooling system where the dry cooling section can address the entire thermal load up to 90 ^{o}F (30 ^{o}C).

Figure 15-4. Representative Parallel Wet-Dry Cooling System Performance[608]



15.4 Tragedy of the Commons

Geothermal plants are very expensive to build. The CPUC estimates the capital cost of a new geothermal plant at $6,300/kW.[609] The cost of retrofitting an existing plant with an air-cooled condenser, or to build a new plant with an air-cooled condenser, would be in the range of $200/kW. In the case of a new plant, the dry cooling alternative to a wet cooling tower would add about 3 percent more cost to an already expensive plant. However, new geothermal plants will not be built with dry cooling systems without state regulations or policies in place that require water use to be minimized in geothermal plant cooling systems.

This is an example of the tragedy of the commons. It is in the strategic interest of the state that its geothermal reservoirs are developed and operated in a manner that assures their long-term viability. That has not happened at The Geysers.

A single operator employing a state-of-the-art dry cooling system to minimize water use at The Geysers would make little difference in the long-term, as other operators with wet cooled plants located around the dry-cooled plant would continue withdrawing water at unsustainable rates. All existing plants would have to be retrofit with minimum water use cooling systems to achieve the objective of sustainable long-term pressure stability in the geothermal reservoir. Otherwise the operators with lower cost, high water consumption cooling towers will gain an unfair economic advantage over operators that are protecting the long-term sustainability of the geothermal resource.

Continuous injection of large amounts of treated wastewater imported via the Southeast Geysers Effluent Pipeline has allowed The Geysers to continue operating at an output of about 900 MW, approximately half its nameplate capacity of around 2,000 MW. The Geysers is on a form of artificial life support, and would eventually cease to be a significant power generation resource without this life support. This cannot be considered a sustainable resource.

However, the Southeast Geysers Effluent Pipeline is an example of an effective collective response to a generalized geothermal resource decline problem that could not be resolved by individual plant operators. NCPA describes the partnership formed to build the pipeline, and significance of the pipeline to ongoing geothermal electricity production, in this passage:[610]

> "The most significant effect on increasing NCPA's recoverable steam reserves came from the construction and operation of the Southeast Geysers Effluent Pipeline project. This $34.1 million project with Calpine, Unocal and the Lake County Sanitation District as partners has delivered over 6 billion gallons of lake water and treated sanitation plant effluent to the Geysers since startup in September 1997, for increased injection and a resulting increase in injection-derived steam. NCPA's one-third share of the water doubled its availability of injectate, and the total amount of steam capable of being produced over the next twenty years is expected to be increased from 238 to 401 billion lbs., resulting in a 70 percent increase in the amount of electricity capable of coming from NCPA's geothermal operations."

Funding for the Southeast Geysers Effluent Pipeline came from NCPA, Calpine, Unocal, PG&E, California Energy Commission, BLM, U.S. Department of Energy, U.S. Environmental Protection Agency, U.S. Economic Development Agency, and Lake County ratepayer indebtedness.[611]

At some point, either due to population increase or drought conditions, Lake County Sanitation District may determine it cannot afford to continue sending 8 million gallons a day of lake water and treated wastewater to The Geysers. At that time the geothermal plants at The Geysers would need to adapt to substantially less make-up water or permanently shut down.

15.5 Benefits of Cooling System Retrofits

A comprehensive retrofit of existing geothermal plants at The Geysers to parallel wet-dry cooling would result in a reduction in geothermal fluid consumptive use of up to 90 percent. Reduced fluid consumption would lead to the potential for significant additional geothermal output.

The geothermal power increase potential from a comprehensive retrofit of the eighteen 110 MW (design rating) geothermal plants at the Geysers may be substantial. If another 300 MW of additional output could be regained from the geothermal field by a comprehensive wet-dry cooling retrofit program, these 300 MW would be the least expensive new renewable energy in the state. This assumes around 16 to 20 cells per geothermal plant at an installed cost of about $1.5 million per cell.[612,613] This equates to a cost of approximately $500 million for the retrofit of the entire fleet of geothermal plants at The Geysers.

The total annual additional electricity production from 300 MW of new geothermal capacity would be about 2 million MWh.[614] The annual expense of the cooling system retrofits would be around $50 million per year.[615] Therefore, the cost of this additional geothermal electricity would be on the order of $50 million per year divided by 2 million MWh per year, or about $24/MWh. Even if only an additional 100 MW of output could be recovered, the LCOE of this additional output would still be inexpensive at around $60/MWh.

15.6 Conclusions and Recommendations

- Parallel wet-dry cooling retrofits of The Geysers geothermal plants would improve the sustainability of The Geysers and lead to an increase in production.

- Parallel wet-dry cooling retrofits could increase output from The Geysers at relatively low cost.

- The environmental impact of a cooling retrofit program would be positive, as the cooling retrofits would improve the sustainability of existing plants at The Geysers with no new environmental impacts.

- New plants at The Geysers should be dry-cooled, to avoid further depletion of the geothermal resource.

- The CEC should conduct a technical evaluation to verify the cost of retrofits of geothermal plants to parallel wet-dry cooling and the likely increase in geothermal output made possible by the retrofits.

- If the CEC evaluation demonstrates that the parallel wet-dry cooling retrofit program would result in a substantial increase in output from The Geysers at reasonable cost, the CPUC should authorize PG&E and SCE to recover from ratepayers the cost to the geothermal plant operators of the cooling system retrofits.

- The same CEC evaluation should be used by NCPA to support recovery from NCPA member POU ratepayers of the cost to retrofit the two NCPA geothermal plants to parallel wet-dry cooling.

16. Battery Storage

The potential application of energy storage technologies ranges from bulk storage within the transmission system to smaller storage projects within the distribution system. The development of large-scale energy storage systems is moving forward in California. For example, in 2010 FERC approved incentive rates for Western Grid Development's utility-scale battery storage projects in California.[616] These projects are intended to address specific transmission reliability problems identified by CAISO. Also, the Southern California Public Power Authority signed an agreement with Ice Energy in January 2010 to develop 53 MW of load-shifting storage capacity.[617] PG&E or third parties can deploy energy storage systems in conjunction with fixed PV arrays or wind farms to assure high levels of availability during peak demand periods as an alternative to contracting for a new generation of peaking gas turbines to fulfill the same function.

AB 2514, signed into law in September 2010, directs the CPUC to open a proceeding by March 2012 to determine the amount of energy storage, if any, to be developed by the IOUs.[618] Similar language is included for POUs. The bill initially contained specific energy storage targets. These targets included energy storage equivalent to 2.25 percent of the daily peak load by 2014, and 5 percent of the daily peak load by 2020.[619] Daily peak load is defined as a utility's average peak electrical demand over the previous five years. On a statewide level, assuming an average statewide peak load of 50,000 MW, this is equivalent to somewhat over 1,000 MW of energy storage in 2014 and 2,500 MW of energy storage in 2020.[620]

Specific percentage energy storage targets were dropped from the final version of AB 2514. The CPUC proceeding will set the energy storage targets.

16.1 Overview of Energy Storage Technologies

Table 16-1 describes the three common categories of energy storage applications.[621]

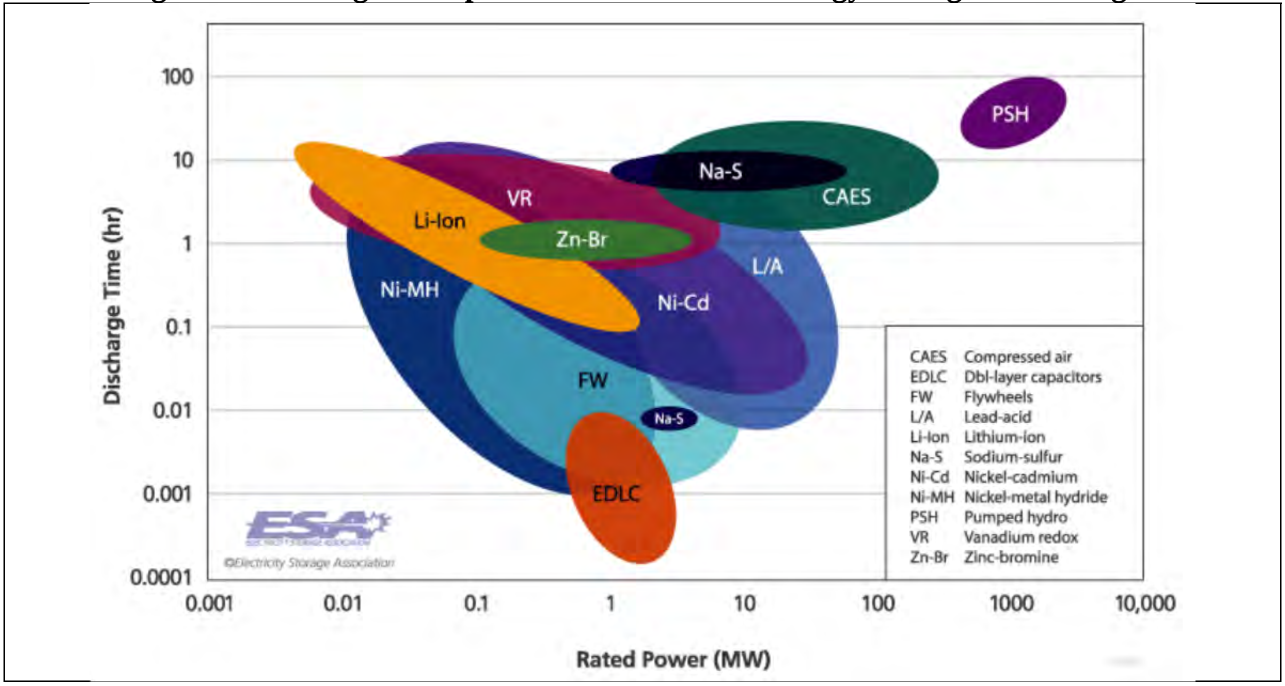
Table 16-1. Three Categories of Energy Storage

Common Name	Example Applications	Discharge Time Required
Power quality	Transient stability, frequency regulation	Seconds to minutes
Bridging power	Contingency reserves, ramping	Minutes to one hour
Energy management	Peak-shaving, firm capacity, T&D deferral	hours

Figure 16-1 identifies the range of capabilities of each energy storage category. The energy management category, which addresses the ability to shift bulk energy over periods of a few hours or more, is the category of interest in BASE 2020.

Lead-acid batteries are used in automotive applications and are also used extensively in off-grid PV systems. Thick plate sealed lead-acid batteries designed specifically for off-grid PV applications are relatively low cost and have a useful life of 15 to 20 years.[622]

Figure 16-1. Range of Capabilities of Different Energy Storage Technologies



For many batteries, there is considerable overlap between energy management and the shorter-term applications listed in Table 16-1. Batteries can generally provide rapid response, which means that batteries used for energy management can potentially provide services over all the applications and timescales. In the U.S., a primary application of energy management batteries has been the deferral of T&D system upgrades.[623]

The most mature high-temperature battery is the sodium-sulfur battery, which had more than 270 MW of worldwide installed capacity as of 2009.[624] PG&E is developing two sodium-sulfur battery projects as part of its *Smart Grid Deployment Plan 2011 - 2020*.[625] The first is a 4 MW project intended to enhance power quality and provide load-leveling. The second is a 2 MW project intended to optimize a nearby PV installation and participate in the CAISO ancillary services market. These projects are expected to be online by December 2012.

Concern among Japanese utilities over the frequency regulation challenges of wind power, due to output fluctuations under some weather conditions, has slowed wind power development in the country.
In an effort to increase wind power development, Japan constructed the first large-scale integrated wind and battery storage project at Futamata, Japan in 2008. As shown in Figure 16-2, 34 MW of sodium-sulfur battery storage is integrated with the 51 MW wind farm to allow the wind power output to be flattened into a near constant output, baseload profile.[626]

Figure 16-2. 34 MW Sodium-Sulfur Battery Storage System[627]

Wind power concentrated in one or two primary development areas has the potential for large and rapid fluctuations in output. Therefore, wind power: 1) is a primary candidate for coupling with energy storage to dampen the impact of rapid output fluctuations on the grid, and 2) may need to be limited in the renewable energy mix to reduce the amount of back-up power necessary for frequency regulation and reliability support during peak demand periods.

16.2 Economic Benefits of Energy Storage as Peaking Capacity

Lead-acid batteries have been integrated into multi-MW storage systems for peak-shaving applications. An analysis prepared by the California Energy Storage Association, comparing the performance of an actual 10 MW peak-shaving system consisting of off-the-shelf lead-acid batteries to a simple cycle gas turbine, indicates that the lead-acid battery system produces lower cost peaking power.[628] Lead-carbon batteries may provide a cost-effective alternative to thick plate lead acid batteries when the lead-carbon alternative reaches mass production.[629]

Energy storage associated with PV systems or wind farms, that can be discharged as needed by the utility, serves the same function as a peaking gas turbine. Energy storage configured to be available to the utility at its discretion should receive the same capacity payments that would otherwise be directed to new peaking gas turbine capacity. The fixed cost of new peaking gas turbine capacity is $303/kW-yr.[630] Over a 15-year period, the total cost of this peaking gas turbine capacity to PG&E ratepayers would be: 15 years × $303/kW-yr = $4,545 per kW of capacity.[631] Therefore the value of battery storage to fill this same function, assuming a 15-year minimum battery lifetime, would be $4,545 per kW of battery capacity.

How much battery storage could a residential PV system owner buy for the capacity payment currently paid by PG&E to a new peaking gas turbine operator? Assume a 10 kW PV system in a regulatory environment where a sufficient FIT is in place for a homeowner to install a 10 kW PV system. The equivalent capital budget for the battery storage system, assuming a 15-year minimum lifetime, would be $4,545 per kW x 10 kW = $45,450.

An investment of less than $10,000 would be sufficient to add 3 hours of useable battery storage to a 10 kW PV system using thick plate lead-acid batteries with a minimum service life of 15 years.[632] This storage system would provide 3 hours of capacity at 10 kW, a total of 30 kWh of useful supply. Battery storage would be a more cost-effective peaking capacity alternative than a new peaking gas turbine.

As of January 1, 2010, battery storage systems qualify under ARRA for the same 30 percent federal investment tax credit as solar systems.[633] The 30 percent investment tax credit would reduce the cost of the batteries in the example used here to less than $7,000. Use of batteries for peaking power would result in significantly less cost than relying on new peaking gas turbine capacity to fulfill the same function.

16.3 400 MW of Battery Storage Integrated with Solano County Wind

Hundreds or thousands of MW of wind turbines concentrated in the same area have the potential to cause abrupt changes in output. It is these areas that would be primary candidates to be matched with utility-scale energy storage, both to prevent instantaneous grid stability problems and to smooth output and shift more production to high demand, high value daytime periods.

The Solano County wind development area is a good candidate for a utility-scale energy storage project. This wind area is most productive in summer months when demand is highest. The recommended size of the storage project would be 400 MW. This is both sufficient to convert the existing 660 MW of wind capacity in Solano County to a base load resource and would match the transfer capacity of the nearby 400 MW Trans Bay Cable.

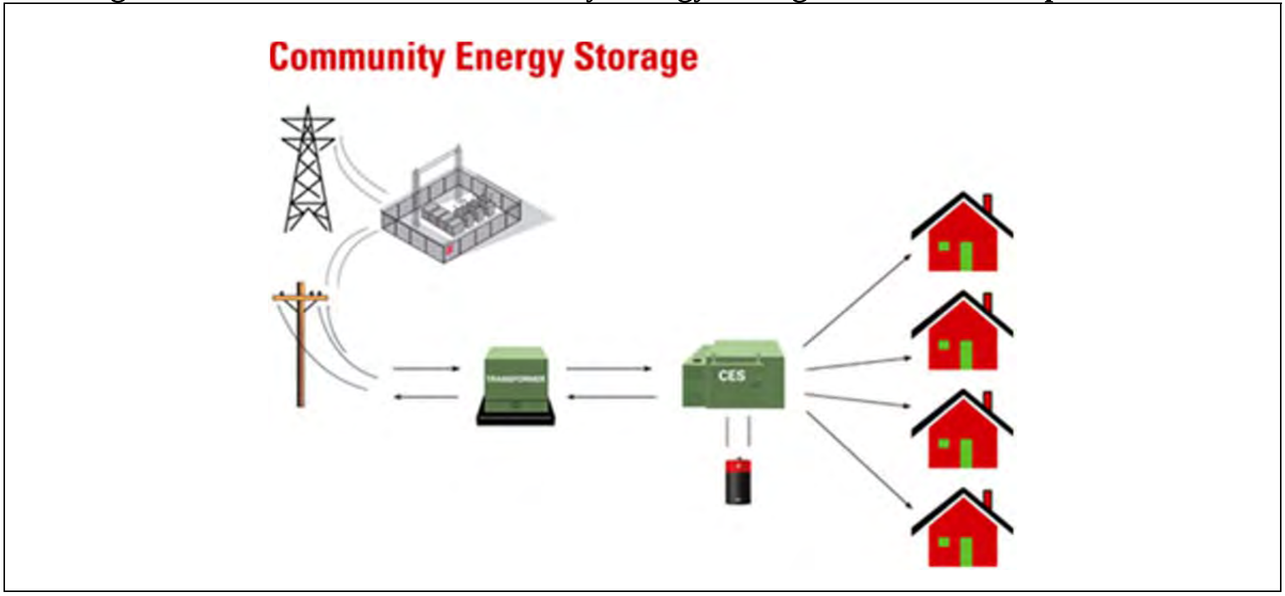
This project would effectively be a scale-up of the Futamata combined wind power and energy storage project in Japan using sodium-sulfide batteries. The purpose of this project would be to demonstrate the effectiveness of this combination to create a base load resource from wind power, and also to assess the economics of this approach compared to other alternatives, such as distributed PV with sufficient battery storage to serve as a base load resource.

16.4 200 MW of Community Energy Storage – Basic Building Block of Microgrids

There are thousands of existing off-grid PV systems that operate with battery storage. These systems are the most basic form of microgrid. Nearly 10,000 off-grid PV systems were operational in the U.S. at the end of 2009.[634] Grid-tied PV systems with battery storage, for residential and commercial PV systems, are available.[635] At least two commercial demonstration projects using battery storage for peak-shaving, a 15 kW system in Maui and a 30 kW system in Georgia, are operational.[636,637]

A recent evolutionary step in microgrid development is Community Energy Storage (CES) units. These units combined sophisticated monitoring and control technology with battery storage at the community level to assure electricity supply and allow operation independent of the grid during outage conditions. The CES units are designed to be expandable, with the capability of managing renewable and conventional generation inputs and additional storage. This platform provides the opportunity to transition from a power management and peaking/emergency power supply function to a fully independent microgrid. Pilot CES projects are underway in AEP Ohio and Detroit Edison service territory.[638,639] The CES concept, and the relationship between the CES and the grid, is shown in Figure 16-3. A description of the capabilities of the CES as a microgrid control center is provided in Appendix H.

Figure 16-3. Schematic of Community Energy Storage and Relationship to Grid[640]



CES units will be clustered in selected neighborhoods and communities, at a ratio of approximately ten homes per CES. Each CES will have a rated output of 25 kW and useable storage of 75 kWh, a total of three hours of useful storage at rated.[641] The installed cost of these CES units, assuming use of thick- plate sealed lead-acid batteries, will be approximately \$2,000/kW.[642,643] The amortized cost of the CES is less than the fixed cost of a new peaking gas turbine.[644] The CES units will be deployed to assure, at a neighborhood level, voltage stability on partly cloudy days when output from local large PV arrays could cycle quickly, to protect the community in case of interruption of grid service, and to provide peaking power as required.

The battery storage capacity of the CES units is expandable over time to allow neighborhoods to move toward independent microgrid capability using the CES as control center and battery storage for rooftop PV. CES telemetry has the capability to automatically cycle major electric loads in homes, subject to homeowner approval, such that refrigerator, electric heaters, and other loads can be cycled when the CES battery storage system is operating to extend battery operation.

A total of 200 MW of CES systems will be installed by 2020 in neighborhoods and business districts throughout the Bay Area. The long-term objective of CES deployments is to gradually displace night-time output from the grid with solar power stored in batteries. The shifting of output from existing large hydro generation to evening hours, when PV is no larger producing electricity, will minimize the amount of CES and other battery storage infrastructure.

16.5 Conclusions and Recommendations

- Battery storage can be a lower-cost alternative to peaking gas turbines.
- Sodium-sulfide batteries are a good match for wind farm output from a wind development area like Solano County with strong summertime electricity production.

- The cost of this battery storage can be paid for through capacity payments that would otherwise be made to peaking gas turbine operators.

- Energy storage is a good match for the high summertime output of Solano County wind farms. The California Energy Commission should conduct a study of the economic and grid reliability benefits of integrating 400 megawatts of battery storage with the Solano County wind farms.

- If the study results are favorable, the state should move forward with the regulatory steps necessary to bring the 400 megawatt battery storage facility online prior to 2020.

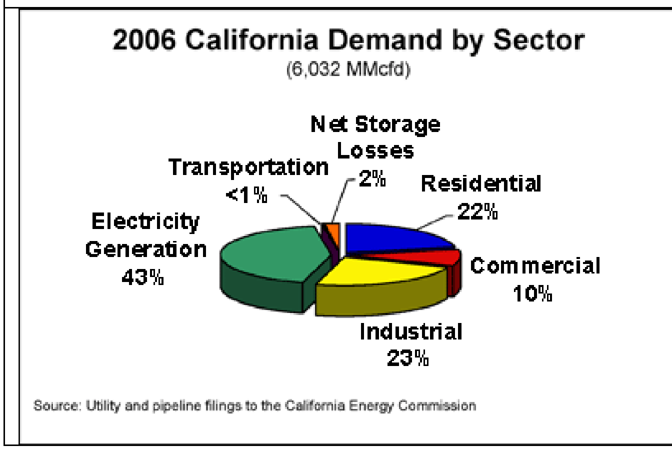
- 200 megawatts of distributed battery storage should be added at the neighborhood level. CES systems are a green substitute for conventional peaking gas turbine resources and an essential building block in eventual community-level microgrids.

17. Solar Thermal - Water and Space Heating

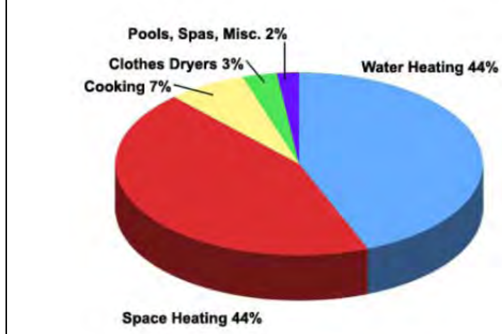
Figure 17-1 shows the natural gas demand sectors that consume California's 6 billion cubic feet per day of demand, as well as the principal sources of natural gas consumption in California homes. About 44 percent of residential natural gas demand is associated with water heating.[645] This represents about 10 percent of California's overall natural gas demand.

Figure 17-1. Profiles of California Statewide and Residential Natural Gas Demand[646]

a. Statewide natural gas demand profile



b. Residential natural gas demand profile



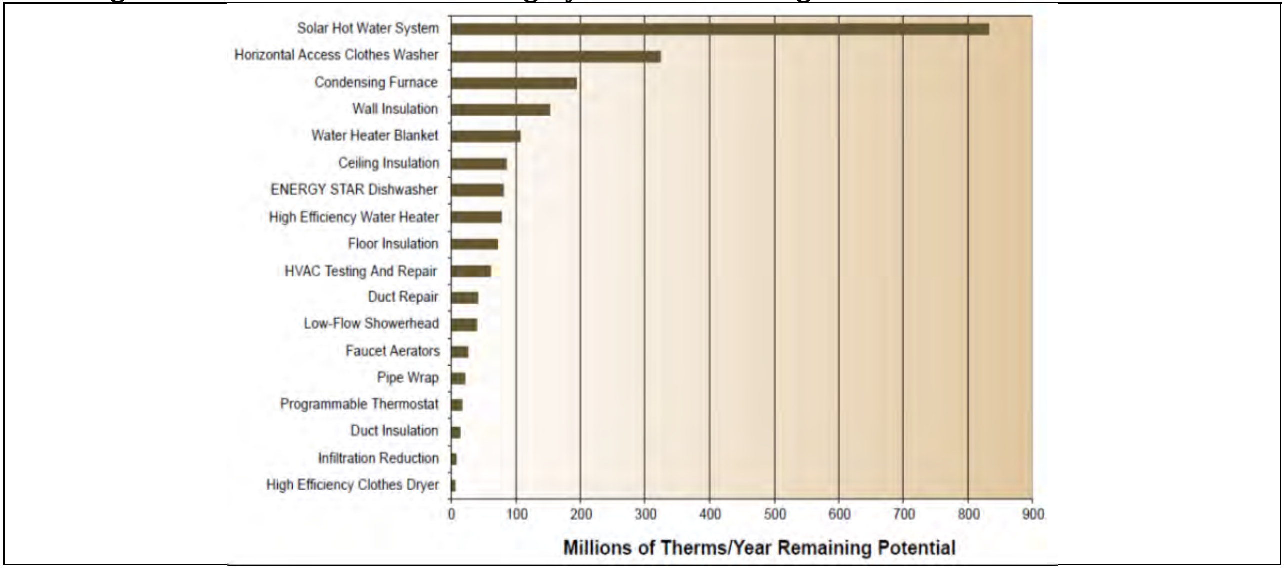
MMcfd = million cubic feet per day

17.1 Solar Hot Water Heating

Solar water heating systems offer the potential for substantial natural gas savings. Figure 17-2 shows the significance of solar water heating for reducing natural gas demand in California homes. An analysis conducted of solar water heating natural gas savings potential in California determined a potential reduction of approximately 1 billion therms per year in homes and 200 million therms per year in commercial buildings.[647] This is equivalent to 120 billion cubic feet of natural gas, about 20 days of natural gas supply for California. This is about 5 percent of the yearly statewide consumption of natural gas.[648]

Installing a solar hot water system on an existing home costs about $6,000. A system installed in a new home may cost as little as $3,000 because of reduced installation costs. The existing 30 percent federal tax credit reduces the cost of a typical system on an existing home from $6,000 to $4,200. This tax credit would reduce the cost of a system on a new home from $3,000 and $2,100.[649] The payback period for a solar hot water heater installed on an existing home is about eight years.[650]

Figure 17-2. Solar Water Heating Systems Have Largest Potential for Reduction[651]

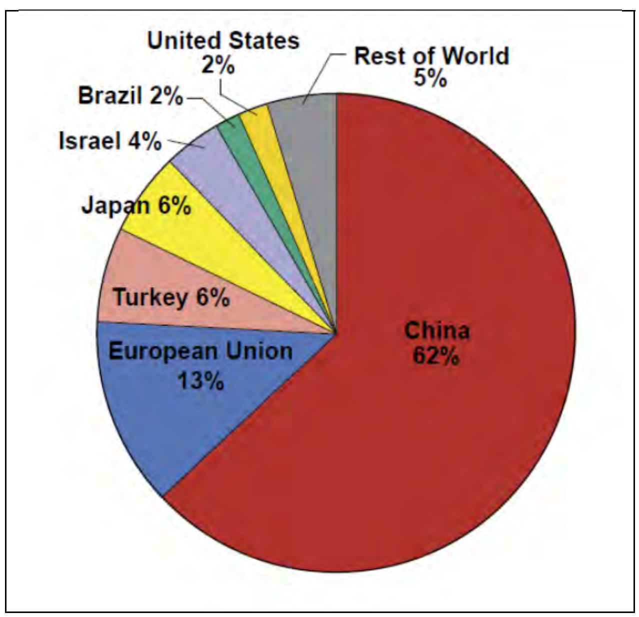


The *Solar Hot Water and Efficiency Act of 2007* authorized a ten-year incentive program for solar water heaters with a goal of promoting the installation of 200,000 systems in California by 2017.[652] This is an average installation rate statewide of 20,000 systems per year. The $350 million *California Solar Initiative (CSI) Thermal Program* is the instrument for achieving the installation of these 200,000 solar water heaters. The *CSI Thermal Program* began accepting rebate applications in May 2010.[653] Ratepayers can apply for cash rebates of up to $1,875 for the installation of solar water heating systems on single-family residential homes.[654] The *CSI Thermal Program* is administered by PG&E in PG&E service territory.

PG&E has approximately 6 million residential and commercial customers. The state's current *CSI Thermal Program* will have to grow to hundreds of thousands of installations per year over the next decade to put substantial downward pressure on residential and commercial natural gas consumption. Successful implementation of the ZNE target for new buildings will require major growth in California's solar water heating manufacturing and installation industry.

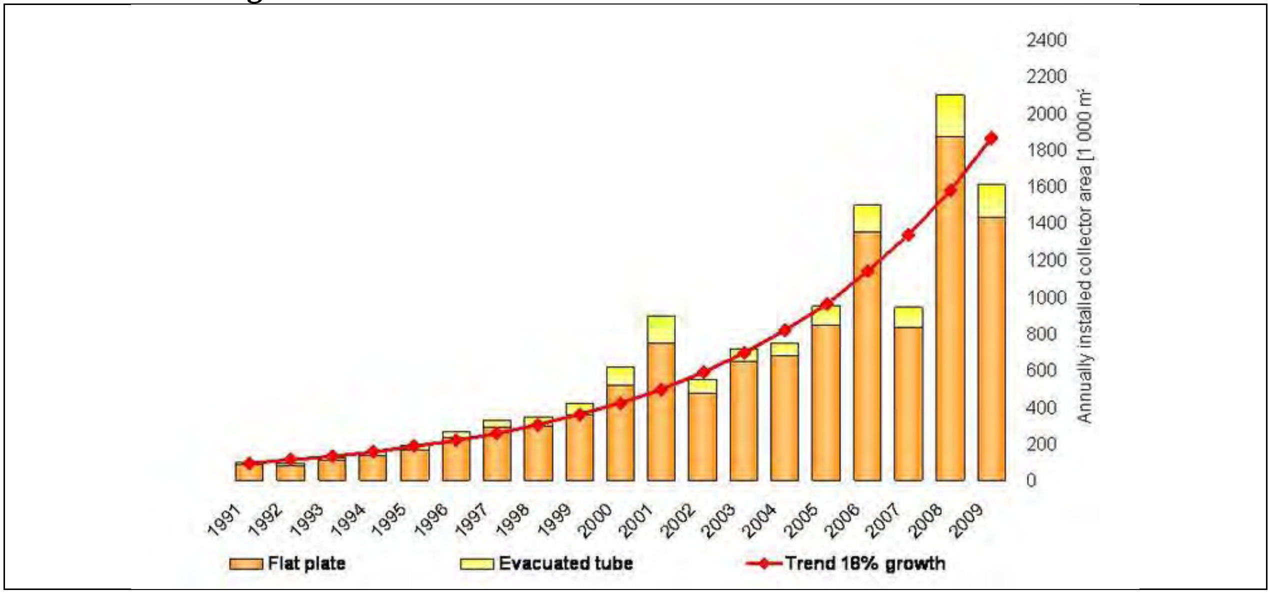
Many countries encourage increased use of solar hot water heating, as shown in Figure 17-3. China leads the worldwide market. On a per-person basis, Israel leads with 90 percent of all homes using solar hot water heating.

Figure 17-3. Solar Hot Water Capacity by Country[655]



Germany had about 1.4 million solar hot water installations online at the end of 2009.[656] The country installed approximately 200,000 solar hot water systems in 2008. The *1999 Market Incentive Program* supports solar heating for domestic hot water and space heating in existing single and multi-family residences.[657] The *2008 Renewable Energy Heat Act* requires that owners of new buildings meet some of the building heating requirement with renewable energy.[658] It applies to residential and commercial buildings. The owner can choose the type of renewable energy to be used. If solar power is used it must cover at least 15 per cent of the heating demand. The German trend in solar hot water installations is shown in Figure 17-4.[659]

Figure 17-4. Trend in German Hot Water Heater Installations



17.2 Solar Space Heating

Solar hot water systems can be used for central air heating. They are the same collectors used in solar domestic water heating systems. Flat-plate collectors are the most common, but evacuated tube and concentrating collectors are also available. A controller operates a circulating pump to move the fluid through the collector.[660]

The simplest storage system option for solar space heating is to use multiple standard domestic water heaters. They are readily available, designed to meet building codes for pressure vessel requirements, are lined to inhibit corrosion, and are configured so it is straightforward to attach pipes and fittings.

The solar heat can be distributed with a radiant floor or with a central forced-air system. In a radiant floor system, a solar-heated liquid circulates through pipes embedded in a thin concrete slab floor. The heat radiates to the room. Radiant floor heating is ideal for liquid solar systems because it performs well at relatively low temperatures. A conventional standard domestic water heater can supply backup heat.

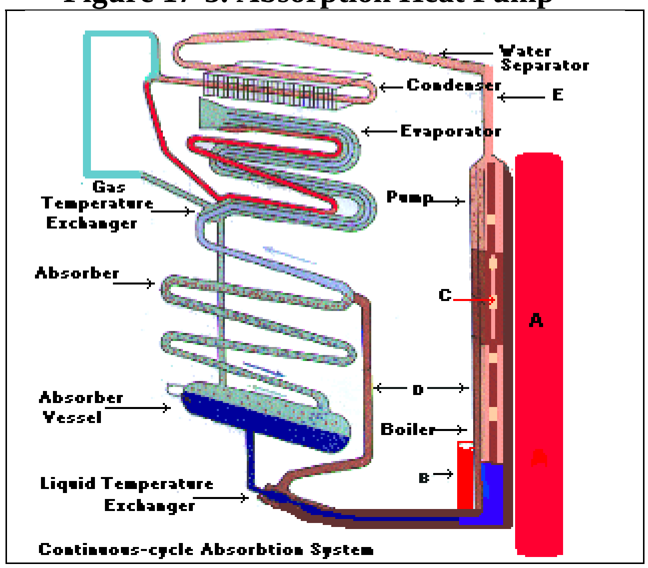
A liquid solar hot water system can be incorporated into a forced-air heating system. The basic design is to place a liquid-to-air heat exchanger, or heating coil, in the main room-air return duct prior to the furnace. Air returning from the living space is heated as it passes over the solar heated liquid in the heat exchanger.

Another alternative is direct solar heating of building make-up air. One example of this type of technology, the SolarWall™, is described in Appendix I.

17.3 Solar and Geothermal Heat Pumps

Absorption heat pumps are driven by a heat source such as natural gas, propane, solar-heated water, or geothermal-heated water. Residential absorption heat pumps use an ammonia-water absorption cycle to provide heating and cooling. The refrigerant, typically ammonia as in a standard heat pump, is condensed in one coil to release its heat. Its pressure is then reduced and the refrigerant is evaporated to absorb heat. If the system absorbs heat from the interior of the home, it provides cooling. If it releases heat to the interior of the home, it provides heating.[661] Figure 17-5 is a schematic of an absorption heat pump.

Figure 17-5. Absorption Heat Pump[662]



The difference between a conventional refrigeration cycle and an absorption heat pump cycle is that the evaporated ammonia is not pumped-up in pressure in a compressor, but is instead absorbed into water. A relatively low-power pump can then pump the solution up to a higher pressure. The problem then is removing the ammonia from the water. That is where the heat source is necessary. The heat boils the ammonia out of the water, starting the cycle again.

A key component in the units available on the market is generator absorber heat exchanger technology. This technology boosts the efficiency of the unit by recovering the heat that is released when the ammonia is absorbed into the water.

Absorption coolers are now commercially available for large residential homes. The 5-ton residential cooler systems currently available are for homes on the scale of 4,000 square feet or more.

17.4 Merit Order Cost Benefits of Natural Gas Reduction

The merit order impact on the wholesale price of electricity of PV and CHP DG resources also holds true for natural gas. The natural gas savings realized by high levels of solar hot water heating in California would lead to large savings for all natural gas consumers by putting downward pressure on the wholesale price of natural gas.

A 2006 study by the American Council for an Energy-Efficient Economy (ACEEE) modeled the effects of natural gas savings in California, Oregon, and Washington on the price of the natural gas. The study found that efficiency measures leading to a 5 percent reduction in natural gas consumption would be accompanied by at least \$5 billion per year in natural gas cost savings.[663] The California market accounts for about 80 percent of these savings.

The ACEEE study assumed a 2006 natural gas baseline price of about \$7/MMBtu.[664] The average market price in the West has since declined to about \$4/MMBtu. Assuming California represents 80 percent of the cost savings, and natural price decline has reduced the savings potential by half since the ACEEE study was conducted, the natural gas cost savings potential of a 5 percent reduction in California natural gas consumption would be on the order of \$2 billion per year.

It is this merit order price reduction benefit from the conversion to solar hot water heating systems that should be the basis for a greatly expanded incentive budget for solar hot water heaters. A \$2 billion per year incentive budget would be sufficient to completely pay for about 500,000 solar hot water heater installations per year.[665] There are 12.6 million homes in California.[666] An incentive program of this magnitude could convert about 40 percent of California homes to solar hot water heating by 2020.

17.5 Conclusions and Recommendations

- Solar hot water heating is a cost-effective approach to reducing natural gas usage.
- California has the potential to reduce natural gas consumption by 5 percent by adding solar hot water to homes and commercial buildings.
- California's current target under the *CSI Thermal Program* is to add 200,000 solar hot water heaters by 2017.
- Germany has added up to 200,000 solar hot water heaters in a single year.
- Natural gas savings caused by high levels of solar hot water heating in California will lead to large savings for all natural gas consumers by putting downward pressure on the wholesale price of natural gas.
- Natural gas efficiency measures leading to a 5 percent reduction in natural gas consumption could lead to a \$5 billion per year or more savings in natural gas costs.

- The *CSI Thermal Program* will have to be increased by an order of magnitude to provide a significant reduction in natural gas consumption in California.

- The 2020 solar hot water target for PG&E should be about 1.5 million systems, equal to about 25 percent of PG&E's customers. This is consistent with the target of retrofitting 25 percent of PG&E homes and businesses with rooftop PV by 2020. Over half of these retrofits would occur in the Bay Area.

- A solar hot water retrofit rate of 200,000 per year should be achieved and maintained in PG&E territory by 2020.

- The CEC should conduct an evaluation of the merit price effect of solar hot water heating in California on the market price of natural gas. The calculated merit price benefit to all California natural gas consumers should be included in the solar hot water heater incentive budget to increase the solar hot water heater installation rate.

18. Wind Power in the Bay Area

18.1 Altamont Pass and Montezuma Hills

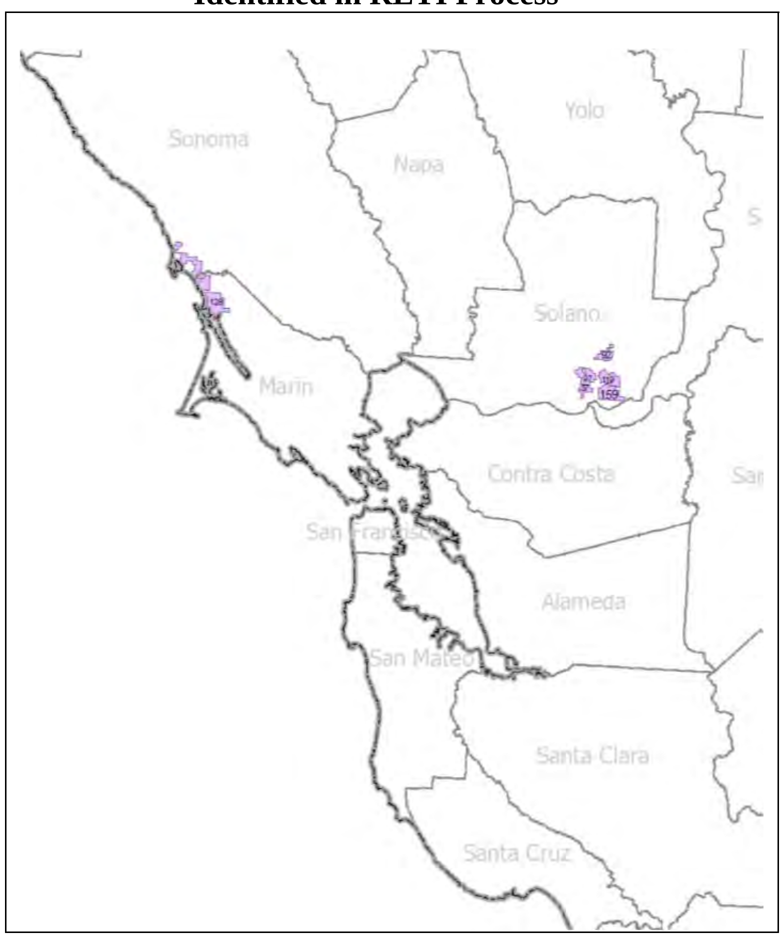
The two principal wind development areas in the Bay Area are the Altamont Pass in eastern Contra Costa and Alameda counties, and the Montezuma Hills areas of Solano County.

The installed wind capacity of Altamont is 576 MW. [667] Altamont began wind power production in 1981. Annual generation is approximately 1,100 GWh.[668] The average capacity factor of Altamont Pass wind projects is about 22 percent.[669]

The Altamont Pass wind turbines were sited along a bird migratory route and in an area with a high concentration of raptors. The early generation wind turbines at Altamont use fast-spinning rotors. More than 1,000 birds are being killed annually by the wind turbines at Altamont. One-half of the birds killed are raptors.[670] The state brokered an agreement between wind developer NextEra and conservation groups in December 2010 to replace 2,400 older, fast-spinning wind turbines at Altamont.[671]

The Montezuma Hills area of eastern Solano County along the Sacramento River has become the primary wind development region in the Bay Area in the last decade. Approximately 760 MW of wind capacity is operating in Solano County.[672] The 2008 capacity factor of the first utility-scale wind farm in Solano County, the 150 MW Shiloh I project in operation since 2006, was 36 percent.[673] As shown in Figure 18-1, RETI identifies the Montezuma Hills as the primary area for new wind projects in the Bay Area. RETI estimates additional wind capacity in the Montezuma Hills of about 1,600 to 1,800 MW.[674]

Figure 18-1. Utility-Scale Wind Sites in Bay Area Identified in RETI Process[675]



The Montezuma Hills area is rural and agricultural. The Solano County wind projects have had far fewer avian deaths than those at Altamont. The projects have not been subject to environmental lawsuits or campaigns to date.

The operational and planned wind projects in Solano County are listed in Table 18-1.

Table 18-1. Actual and Planned Wind Projects in Montezuma Hills[676]

Wind project name	Number of turbines	Capacity (MW)	Status
SMUD-Solano Phase 1 and 2	52	102	Operational
High Winds	90	162	Operational
enXco V	510 × 100 kW 6 × 1.5 MW	60	Operational
Shiloh I	100	150	Operational
Shiloh II	75	150	Operational
Montezuma Wind I	16	37	Operational
Shiloh III[677]	50	102	Operational
SMUD-Solano Phase 3[678]	76	128	Construction
Montezuma Wind II	34	85	Planned
Shiloh IV	79	NA	Speculative

The utility-scale wind potential in the Bay Area is listed in Table 18-2.[679]

Table 18-2. List of Potential Wind Sites Identified by RETI in Bay Area

RETI Wind Project Site Number	County	Potential (MW)
128	Marin/Sonoma	75
37/40/92/97/104/105/119/142/159	Solano	1,600 – 1,800

San Francisco is studying the wind intensity in the city in an effort to promote the use of smaller-scale distributed wind turbines in the urban environment. The San Francisco Department of the Environment is planning to use wind data gathered by the SFPUC and UC Davis to map the city's wind resources and provide wind resource data on a neighborhood-by-neighborhood or city block-by-city block level.[680]

18.2 Conclusions and Recommendations

- The addition of 300 MW of new wind capacity in Solano County, Shiloh III, SMUD-Solano Phase 3, and Montezuma Wind II, either has happened or will happen in the near-term.

- 300 MW of new wind capacity in Solano County should be assumed in BASE 2020.

19. Principal Conclusions

BASE 2020 is a distributed generation strategy for minimizing GHG emissions from electricity usage in the Bay Area. It prioritizes energy efficiency, rooftop and distributed PV, and CHP over conventional power plants to meet the electricity needs of the Bay Area. To a large degree the framework for BASE 2020 is California's strategic energy vision, embodied in California's *Energy Action Plan* and *Energy Efficiency Strategic Plan*.

Achieving BASE 2020 will reduce GHG emissions from the electricity sector by more than 60 percent by 2020 compared to a 2008 baseline, and will reduce peak Bay Area demand on the grid by more than 50 percent. To achieve BASE 2020, the following overarching actions must be taken:

- Energy efficiency funds, currently administered by PG&E, must be transferred to an independent non-profit entity modeled on the Energy Trust of Oregon or to CCAs where they are operational in the state.

- PACE programs should play a major role in maximizing the conversion of existing homes and commercial buildings to ZNE.

- CCA is a viable alternative for California cities and counties to increase local control of electricity supply, increase the rooftop PV component of electricity supply, independently administer public goods charges, and provide price competition to PG&E.

- Effective clean energy payments (feed-in tariffs) must be established for distributed PV and CHP.

- Clean energy payments at or below the avoided cost to PG&E will benefit all PG&E ratepayers. The average avoided cost of PV to PG&E is at least \$0.22/kWh. The average avoided cost of CHP to PG&E is at least \$0.18/kWh. Clean energy payments at rates substantially below these avoided costs to PG&E would be sufficient to create dynamic distributed PV and CHP markets in the Bay Area.

- The Governor's office should convene an independent panel to make a determination regarding the need to replace once-through cooled steam boiler capacity for grid reliability purposes. Available analyses by CAISO and SWRCB reach such different conclusions that, with a potential ratepayer impact of billions of dollars for new natural gas-fired capacity in the balance, a technical consensus must be reached at strategic level before committing to build these gas fired-plants.

- The CEC should quantify the merit order effect of ever-increasing levels of energy efficiency, distributed PV, CHP, and solar hot water heating on the wholesale market price of electricity and natural gas in California.

- In the case of distributed PV and CHP, the results of this merit order evaluation would serve as the basis for shifting all transaction costs, including interconnection costs, to PG&E ratepayers.

- In the case of solar hot water heating, biomethane production, and biogas production, the results of the merit order evaluation would serve as the basis for expanding incentive payments for these natural gas displacement alternatives.

20. References

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[115] California Cogeneration Council, *Pre-Workshop Opening Comments of California Cogeneration Council*, June 4, 2004, CPUC R. 04-04-025, Rulemaking to Promote Consistency in Methodology and Input Assumptions in Commission Applications of Short-run and Long-run Avoided Costs, Including Pricing for Qualifying Facilities.
[116] PG&E, *PG&E Long-Term Procurement Plan, Volume I*, December 11, 2006, p. V-31.
[117] CEC, *California Energy Demand 2009-2020 Adopted Forecast*, December 2009, Form 1.1c - Electricity Deliveries to End Users by Agency (GWH). PG&E bundled electricity deliveries in 2008 were 81,983 GWh. "Bundled" means PG&E both acquires electricity for the customer snd delivers that electricity to the customer.
[118] CPUC Renewable Portfolio Standard webpage: http://www.cpuc.ca.gov/PUC/energy/Renewables/index.htm. Total PG&E sales in 2009 were 79,976 GWh. See: CEC, *California Energy Demand 2009-2020 Adopted Forecast*, December 2009, Form 1.1c. Total renewable sales, at 14.4 percent of total sales = 0.144 x 79,976 GWh = 11,517 GWh.
[119] CPUC RPS webpage: http://www.cpuc.ca.gov/PUC/energy/Renewables/index.htm
[120] See text of SB 2 (1X): http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf.
[121] CEC, *2008 Power Source Disclosure Form*, PG&E.
[122] See text of AB 1890 (deregulation bill): http://www.caiso.com/docs/2004/09/28/200409281045575800.pdf.
[123] CAISO mission statement: http://www.caiso.com/docs/2005/09/28/200509281333048821.html
[124] J. Firooz, *Transmission in Short Supply or Do IOUs Want More Profits?*, Natural Gas & Electricity Journal, July 2010.
[125] Ibid. The transmission rate base column shows the cumulative amount of transmission investment that remains to be recovered from customers by California IOUs as of the indicated year. Transmission rate base is from FERC Form 1. Net electricity supplied by the California IOUs is from the CEC 2009 IEPR, January 2010.
[126] Greenwire, *Electricity: Undersea cable ends San Fran's grid isolation, provides cleaner power*, November 30, 2010.
[127] Trans Bay Cable website: http://www.transbaycable.com/project-sponsors/steelriver-infrastructure-partners/
[128] Bay Citizen, *Shuttered SF Power Plant to Be Demolished*, December 21, 2010.
[129] Base transmission line and substation map was provided by the CEC Cartographic Unit. Trans Bay Cable overlay was added by B. Powers, Powers Engineering.
[130] Renewable Energy Transmission Initiative, *RETI Phase 2A Final Report*, September 23, 2009, Appendix H. See: http://www.energy.ca.gov/2009publications/RETI-1000-2009-001/RETI-1000-2009-001-F-REV2.PDF
[131] Black & Veatch and E3, *Summary of PV Potential Assessment in RETI and 33% Implementation Analysis*, PowerPoint presentation at Re-DEC Working Group Meeting, December 9, 2009, p. 10.
[132] PG&E, *2006 Long-Term Procurement Plan, Volume 1, Section V*, Table Vol. 1, VH-1, p. V-43.
[133] CAISO OASIS database, System Load, July 25, 2006.
[134] CAISO OASIS database, System Load, August 25, 2010.
[135] PG&E, *2006 Long-Term Procurement Plan, Volume 1, Section V*, Table Vol. 1, VH-1, p. V-43.
[136] CAISO, *2011-2012 Transmission Plan – Draft*, January 31, 2012, p. 29. See: http://www.caiso.com/Documents/Draft2011_2012TransmissionPlan.pdf. "In 2011, the ISO-controlled grid peak

demand was 45,545 MW and occurred on September 7, 2011 at 4:30 p.m. The peak demand for PG&E of 19,791 MW occurred on June 21, 2011 at 4:49 p.m."

[137] CEC, California *Electricity Demand 2010 – 2020 Adopted Forecast*, December 2009, p. 2. "Peak demand will grow at 1.3 percent annually." The 2006 one-hour peak was 22,650 MW. The 2010 one-hour peak was 21,180 MW. The forecast peak one-hour load in PG&E territory would be not exceed the 2006 peak until 2016 when it would reach: 21,180 MW × $(1 +.013)^6$ = 22,887 MW. The actual population growth rate in PG&E territory from 2000-2009 was 0.9 percent. Assuming the peak demand growth rate from 2010-2020 is 0.9 percent per year, the peak demand would not exceed the 2006 peak one-hour load until 2018: 21,180 MW × $(1 +.009)^8$ = 22,754 MW.

[138] Ibid, p. V-44.

[139] PowerGen Worldwide, *2009 Projects of the Year*, January 1, 2010.

[140] CAISO, *2011 Summer Loads and Resources Assessment*, April 22, 2011, Table 1, p. 4. NP26 (PG&E) total net summer supply is 28,592 MW, without taking into consideration the "Outages (1-in-2 Generation & Transmission)" line item that CAISO uses for the first time in the 2011 summer load forecast. The CEC, in its *Summer 2011 Electricity Supply and Demand Forecast*, April 2011, Table 2, p. 5, does not include an "Outages" line item. The one-minute peak in NP26 in 2010 was 19,791 MW on June 21, 2011. The difference between the total supply and the actual peak is: 28,592 MW – 19,791 MW = 8,801 MW. See *CAISO 2011-2012 Transmission Plan - Draft*, January 31, 2012, p. 29. "In 2011, the ISO-controlled grid peak demand was 45,545 MW and occurred on September 7, 2011 at 4:30 p.m. The peak demand for PG&E of 19,791 MW occurred on June 21, 2011 at 4:49 p.m." 28,592 MW ÷ 19,791 MW = 1.445. This is an actual reserve margin of 44.5 percent. A total net supply of 22,760 MW would be necessary to maintain a 15% reserve margin with a 19,791 MW peak load. The additional supply beyond 15% available in PG&E territory at the 2010 one-hour peak was 28,592 MW – 22,760 MW = 5,832 MW.

[141] PG&E, *2006 Long-Term Procurement Plan, Volume 1, Section V*, Table Vol. 1, VH-2, p. V-44.

[142] TetraTech, *California's Coastal Power Plants: Alternative Cooling System Analysis*, prepared for the California Ocean Protection Council, February 2008. Installed capital cost of retrofit cooling towers for Pittsburg steam boilers, Units 5 and 6, 650 MW = $193/kW, Chapter L, p. L-25. 720 MW Pittsburg Unit 7 is equipped with wet cooling towers. 650 MW = 650,000 kW. Therefore, 650,000 kW × $193/kW = $125 million.

[143] CEC, *The Use of Heat Rates in Production Cost Modeling and Market Modeling*, April 17, 1998, p. A-13. Pittsburg 5 average heat at 100 percent load = 9,676 Btu/kWh. Pittsburg 6 average heat at 100 percent load = 9,945 Btu/kWh. Pittsburg 5 and 6 average at 100 percent load = (9,676 Btu/kWh + 9,945 Btu/kWh) ÷ 2 = 9,811 Btu/kWh.

[144] CEC, *Marsh Landing Generating Station – Presiding Member's Preliminary Decision*, July 2010, p. 38. "Staff noted that the MLGS will have a net worse case heat rate of approximately 11,124 Btu/kWh. (Exhibit 300, p. 4.1-73.)."

[145] ICF Jones and Stokes, *Electric Grid Reliability Impacts from Regulation of Once-Through Cooling in California*, prepared for Ocean Protection Council and State Water Resources Control Board, April 2008.

[146] CEC, *Committee Workshop on Options for Maintaining Electric System Reliability When Eliminating Once-Through Cooling Power Plants - Transcript*, May 11, 2009, p. 204. Yakout Mansour, CAISO: "MR. MANSOUR: The second thing is that you mentioned that someone has $1.7 -- $117 million to fix all the transmission constraints in the system. Frankly, if you have the name of that person, I'm sure there's some kind of big sale or something like $117 million and let them fix all the stuff in the state as you're saying." B. Powers, p. 206: "MR. POWERS: And I think this is -- Mr. Mansour brings up a very important point, which is the environmental community is working with the ICF Jones and Stokes report -- reliability report. If the ISO doesn't have it or hasn't read it, that's a problem because what that reports states is that with a phase-out over the next years, we can retire all of the coastal OTC boiler plants. And what we would need is a minimum upgrade -- transmission reinforcement upgrade, a value of $135 million."

[147] Ibid, p. 106, p. 108. "MR. PENDERGRAFT: Hello. Eric Pendergraft with AES. We own Alamitos, Redondo Beach and Huntington Beach, all in the LA basin about just over 4,200 megawatts I think, depending on what statistics you use. . . We have performed high level retrofit studies for closed cycle cooling, both wet and dry cooling. As one might expect there are significant land constraints as well as permitting issues. They're expensive, you know, a rough ballpark for wet cooling at our sites it's approximately $125 or $115 a kilowatt. So for our 4,000 megawatts you're looking at, you know, 500 million dollars, half a billion dollars to retrofit with wet cooling."

[148] TetraTech, *California's Coastal Power Plants: Alternative Cooling System Analysis*, prepared for the California Ocean Protection Council, February 2008. Installed capital cost of retrofit cooling tower(s): Moss Landing combined cycle, Units 1 and 2, 1080 MW = $69/kW, Moss Landing steam boilers, Units 6 and 7, 1,404 MW = $191/kW, Chapter J, p. J-27. Contra Costa steam boilers, Units 6 and 7, 680 MW = $144/kW, Chapter B, p. B-27.

Pittsburg steam boilers, Units 5 and 6, 650 MW = $193/kW, Chapter L, p. L-25. 720 MW Pittsburg Unit 7 is equipped with wet cooling towers.
[149] CEC, *Comparative Costs of California Central Station Electricity Generation*, January 2010, Table 14, p. 54. Capital cost of 49.9 MW simple cycle turbine = $1,292/kW.
[150] NREL press release, *NREL Study Shows Power Grid can Accommodate Large Increase in Wind and Solar Generation*, May 20, 2010.
[151] CAISO OASIS database, System Load, August 25, 2010: http://oasis.caiso.com/mrtu-oasis/home.jsp?doframe=true&serverurl=http%3a%2f%2farptp10%2eoa%2ecaiso%2ecom%3a8000&volume=OASIS
[152] Solano County Department of Resource Management, *Report to Solano County Planning Commission on – Shiloh III Wind Energy Project DEIR*, July 15, 2010. See: http://www.co.solano.ca.us/civica/filebank/blobdload.asp?BlobID=9194
[153] Contra Costa Units 6 and 7 (boilers) = 680 MW. Gateway combined cycle (Contra Costa Unit 8) = 590 MW. Pittsbugh Units 5, 6, and 7 (boilers) = 1,370 MW. Los Medanos combined cycle = 594 MW. Delta Energy Center combined cycle = 860 MW. Total = 4,094 MW.
[154] NREL press release, *NREL Study Shows Power Grid can Accommodate Large Increase in Wind and Solar Generation*, May 20, 2010.
[155] PG&E, *Bundled Procurement Plan - Order Instituting Rulemaking To Integrate And Refine Procurement Policies And Consider Long-Term Procurement Plans*, CPUC Rulemaking R,10-05-006. March 25, 2011, pp. 1-2. "The Energy Action Plan includes a preferred resource order to achieve California's energy and environmental policy goals: Energy Efficiency ("EE"), Demand Response ("DR"), renewable resources, Distributed Generation ("DG") and clean efficient conventional facilities."
[156] PG&E, *2006 Long-Term Procurement Plan, Volume 1*, December 11, 2006, p. V-1.
[157] Ibid, p. V-2.
[158] CPUC Energy Division, *2006-2008 Energy Efficiency Evaluation Report – Draft*, April 15, 2010.
[159] See CPUC Decision D.07-09-043: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/73172.htm
[160].Ibid.
[161] CPUC Energy Division, *2006-2008 Energy Efficiency Evaluation Report – Draft*, April 15, 2010. See: http://www.dra.ca.gov/NR/rdonlyres/07ED3986-1D4F-455B-B3FF-B1AA96482022/0/200608DraftFinalEDEvaluationReport.pdf, Table 23, p. 96.
[162] CPUC, *California Long-Term Energy Efficiency Strategic Plan*, January 2011 Update, p. 53.
[163] PG&E central air conditioner webpage: http://www.pge.com/myhome/saveenergymoney/savingstips/centralair/index.shtml
[164] PG&E, *2006 Long-Term Procurement Plan, Volume 1, Section V*, December 11, 2006, p. V-28.
[165] CPUC Decision D.10-12-048, *Decision Adopting the Renewable Auction Mechanism*, December 16, 2010. See: http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/128432.pdf
[166] PG&E, *Application for Rehearing of Decision D.10-12-048 - Decision Adopting The Renewable Auction Mechanism*, January 18, 2011, p. 1.
[167] CEC, *California Electricity Demand 2010 – 2020 Adopted Forecast*, December 2009, p. 72. Figure 44: PG&E Planning Area Self-Generation Peak Forecasts.
[168] Ibid, p. IV-24, p. IV-25.
[169] Ibid, p. IV-26. Table IVC-5, Volume 1.
[170] CPUC, Decision D.10-12-035, *Decision Adopting Proposed Settlement*, December 16, 2010, p. 41. "The Short-Run Avoided Cost (SRAC) included in the Proposed Settlement is based on the current Commission-approved SRAC pricing formula and achieves the goal of ultimately transitioning to a market heat rate to determine SRAC by January 1, 2015."
[171] CPUC, *CHP Program Settlement Agreement Term Sheet*, October 8, 2010, p. 31. This document is an attachment to CPUC Decision D.10-12-035, *Decision Adopting Proposed Settlement*, December 16, 2010.
[172] CEC, *California Electricity Demand 2010 – 2020 Adopted Forecast*, December 2009, Form 1.1c. 2008 PG&E bundled delivered electricity = 81,983 GWh. Total statewide delivered electricity = 276,509 GWh. PG&E percentage of total = 81,983 GWh/276,509 GWh = 0.296. 4,000 MW x 0.296 = 1,184 MW.
[173] CPUC Renewable Auction Mechanism webpage: http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm
[174] CPUC Decision D.10-12-035, *Decision Adopting Proposed Settlement*, December 16, 2010, p. 41.
[175] Ibid, p. 41.

[176] CPUC Rulemaking R.08-06-024, *Rulemaking on the Commission's Own Motion into Combined Heat and Power Pursuant to AB 1613 – Motion of PG&E, SCE, and SDG&E for Stay of Decision D.10-12-055*, January 6, 2011.
[177] CPUC Market Price Referent webpage, 20-year 2009 MPR for projects with a 2011 start date is $0.10098/kWh: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_RESOLUTION/111386.htm
[178] AB 162 as chaptered: http://www.energy.ca.gov/power_source_disclosure/documents/ab_162_bill_20091011_chaptered.pdf
[179] Ibid.
[180] Power Engineering, United States: *Mt. Poso cogeneration plant undergoes 100% conversion*, February 27, 2012. See: http://www.power-eng.com/news/2012/02/27/united-states-mt-poso-cogeneration-plant-undergoes-100-conversion.html.
[181] CPUC press release, *CPUC takes another step toward state's renewable energy goal with approval of PG&E contracts*, July 29, 2010.
[182] CARB, *California Cap-and-Trade Program*, Resolution 10-42, December 16, 2010, p. 12.
[183] CEC, *2008 Net System Power Report*, July 2011, Figure 3, p. 6.
[184] CEC, *California Electricity Demand 2010 – 2020 Adopted Forecast*, December 2009, Form 1.1c. 2008 PG&E bundled delivered electricity = 81,983 GWh. 2008 PG&E unbundled (Direct Access) delivered electricity = 6,376 GWh. Therefore Direct Access percentage is 6,376 GWh/(81,983 GWh + 6,376 GWh) = 7.2 percent of bundled delivered electricity.
[185] PG&E, *2006 Long-Term Procurement Plan, Volume 1, Section V*, December 11, 2006, p. VI-11.
[186] CEC, *California Electricity Demand 2010 – 2020 Adopted Forecast*, December 2009, Form 1.1c. 2010 PG&E bundled delivered electricity = 80,192 GWh. 20%, or 16,038 GWh, is renewable energy, leaving of non-RPS energy resources of 64,154 GWh. 2020 PG&E bundled delivered electricity = 91,010 GWh. 33%, or 30,033 GWh, is renewable energy, leaving non-RPS energy resources of 60,977 GWh. This represents a 5 percent reduction in 2020 over GHG emissions in 2010 [(64,154 GWh – 60,977 GWh)/64,154 GWh = 0.0495].
[187] Ibid, p. VI-11. "Additional swings in hydro availability can further contribute to increase CO2 emissions in a given year. For example, a 5,000 GWh reduction in hydro from a normal to a dry hydro scenario would increase CO_2 emissions by another 12-13%." [(64,154 GWh – (60,977 GWh + 5,000 GWh))/64,154 GWh = -0.0284]. This represents an increase in GHG emissions in 2020 of approximately 3 percent in a low hydro year.
[188] PG&E, *Bundled Procurement Plan – Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans*, R.10-05-006, March 25, 2011, Table V-4, p. 81. See: http://www.cpuc.ca.gov/NR/rdonlyres/C236A763-808D-4F01-8575-5757FC4B4373/0/PGE2010LTPP1AB57BundledProcurementPlanwith041511Errata.pdf. Physical CO_2 MMT: 2011 = 15.1; 2019 = 16.2; 2020 = 14.8. 2019 GHG emissions increase = 16.2/15.1 MMT = 1.073 (+7.3%).
[189] CARB Cap-and-Trade Program webpage: http://arb.ca.gov/cc/capandtrade/capandtrade.htm.
[190] CARB cap-and-trade program webpage, Table – California GHG Emissions – Forecast (2008-2020), October 28, 2010: http://www.arb.ca.gov/cc/inventory/data/tables/2020_ghg_emissions_forecast_2010-10-28.pdf
[191] CEC, *2008 Net System Power Report*, July 2009.
[192] Ibid, p. 9.
[193] CEC, *Power Source Disclosure Program Draft Regulations – Workshop*, November 4, 2010. See: http://www.energy.ca.gov/power_source_disclosure/notices/2010-11-04_Notice_POU_Workshop.pdf. "AB 162 removes the requirement that retail suppliers provide net system power on customer disclosures."
[194] AB 162 as chaptered: http://www.energy.ca.gov/power_source_disclosure/documents/ab_162_bill_20091011_chaptered.pdf
[195] CEC, *2008 Net System Power Report*, July 2009, Table 4, p. 10. The CEC estimated that wholesale market power purchases in 2008 consisted of 33.7 percent coal power and 41.9 percent natural gas power. The composite CO_2 emission factor for this fuel mix composition is 0.55 ton CO_2 per MWh.
[196] PG&E, *Greenhouse Gas Emission Factors Info Sheet*, April 8, 2011, p. 3. See: http://www.pge.com/includes/docs/pdfs/shared/environment/calculator/pge_ghg_emission_factor_info_sheet.pdf. The 2008 composite CO_2 emission factor for PG&E electricity generation sources is 641 lb/MWh.
[197] CEC, *Thermal Efficiency of Gas-Fired Generation in California, - Staff Paper*, August 2011, Table 2, p. 3. The composite heat rate of gas-fired resources is 8,566 Btu/kWh, or 8.566 MMBtu/MWh. The CO_2 emission rate of natural gas combustion is 117 lb CO_2/MMBtu. The CO_2 emission rate of natural gas-fired generation in California is 8.566 MMBtu/MWh × 117 lb CO_2/MMBtu = 1,002 lb CO_2/MWh (0.50 tons CO_2/MWh.).

[198] ARB AB 32 Cap-and-Trade Program webpage, Table – California GHG Emissions – Forecast (2008-2020), October 28, 2010: http://www.arb.ca.gov/cc/inventory/data/tables/2020_ghg_emissions_forecast_2010-10-28.pdf. See footnote - unspecified imported electricity is assumed to have a CO_2 emission factor of 959.6 lb CO_2/MWh.
[199] CPUC, *California Electricity Demand 2010 – 2020 Adopted Forecast, December 2009*, Form 1.1c.
[200] CPUC, *California Electricity Demand 2010 – 2020 Adopted Forecast, December 2009*, Form 1.1c. See: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html. 2008 PG&E bundled and Direct Access deliveries = 88,359 GWh. 2008 Bay Area POU deliveries = 5,327 GWh. California Energy Consumption Database Management System, Electricity Consumption by County: http://www.ecdms.energy.ca.gov/. Nine Bay Area counties electricity consumption in 2008 = 57,316 GWh. Therefore, the percentage of PG&E bundled and Direct Access usage in the nine Bay Area counties = (57,316 GWh – 5,327 GWh)/88,359 GWh = 0.59.
[201] Ibid.
[202] CPUC RPS webpage: http://www.cpuc.ca.gov/PUC/energy/Renewables/index.htm
[203] CPUC Division of Ratepayer Advocates, *Green Rush - Investor-Owned Utilities' Compliance with the Renewables Portfolio Standard*, February 2011, Figure 2, p. 10.
[204] Ibid, p. 10.
[205] CPUC, *33% Renewable Portfolio Standard Implementation Analysis Preliminary Results*, June 2009, p. 87.
[206] BLM press release, *BLM Concentrating on Renewable Energy Projects That Could Meet Stimulus Funding Deadline*, December 29, 2009: http://www.blm.gov/wo/st/en/info/newsroom/2009/december/0.html
[207] CPUC, *Renewables Portfolio Standard Quarterly Report – 4th Quarter 2010*, p. 6. See: http://www.cpuc.ca.gov/NR/rdonlyres/CFD76016-3E28-44B0-8427-3FAB1AA27FF4/0/FourthQuarter2010RPSReporttotheLegislature.pdf. "The CPUC approved 22 contracts in the third quarter of 2010, the highest number of contracts approved in a quarter since the conception of the program. This spike in contract processing resulted from projects seeking the federal grant in lieu of the tax credit, which was set to expire December 31, 2010. As a result, the CPUC prioritized review and approval of those contracts so that they could qualify for the federal grant."
[208] www.sustainablebusiness.com, *Interior Sued Over Approval of Fast-Track Solar Projects*, January 5, 2011.
[209] BLM fast track renewable energy projects: http://www.blm.gov/wo/st/en/prog/energy/renewable_energy/fast-track_renewable.html
[210] Sandia National Laboratory, *Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide - A Study for the DOE Energy Storage Systems Program*, February 2010, p. 27.
[211] Xenergy, Inc., *California's Secret Energy Surplus – The Potential for Energy Efficiency*, September 23, 2002, p. A-6.
[212] RETI, *RETI Phase 1B Final Report*, January 2, 2009, p. 6-23. Note that the profiles shown are for W_{ac} output, and assume a dc-to-ac conversion efficiency of approximately 80%.
[213] Monthly MWh data for 150 MW Shiloh I wind project: U.S. DOE, Energy Information Administration, 2008 Form 923 Monthly Time Series.
[214] Cliff Murley – SMUD, *Energy Storage Projects at SMUD*, presented at CEC Workshop: Wind Storage Enhanced Technologies on the Grid, October 3, 2007, pp. 6-7. Note that SMUD peak demand shown in graphic is later in the day, 5 pm to 6 pm, than the 2 pm to 5 pm peak range in PG&E territory.
[215] PG&E, *2006 Long-Term Procurement Plan, Volume II*, December 11, 2006, p. I-28.
[216] Ibid, p. I-29.
[217] www.autoblog.org, *Nissan Leaf snags 99 mpg rating on official EPA sticker*, November 22, 2010. See: http://www.autoblog.com/2010/11/22/nissan-leaf-snags-99-mpg-rating-on-official-epa-sticker/4
[218] 10,000 miles/yr ÷ 3.4 miles/kWh = 2,941 kWh/yr. 2,941 kWh/yr ÷ 365 days/yr = 8.06 kWh/day.
[219] Ibid, p. I-29.
[220] CAISO market monitoring report, August 18, 2011, p. 3: http://www.caiso.com/Documents/110825DepartmentofMarketMonitoringUpdate.pdf. "These price trends may be further exacerbated by the April 2011 increase in the bid cap from $750 to $1,000/MWh."
[221] PG&E webpage, Facts - What Is Peak Day Pricing?: http://www.pge.com/mybusiness/energysavingsrebates/demandresponse/peakdaypricing/facts/. Peak day pricing adder for high demand (> 200 kW) commercial customers is $1.20/kWh.
[222] CPUC A.10-03-012, Application of PG&E to Implement Assembly Bill 920 (2009) Setting Terms and Conditions for Compensation for Excess Energy Deliveries by Net Metered Customers, *Proposal of the Solar Alliance and Vote Solar Initiative for a Net Surplus Compensation Rate and Responses to Scoping Memo Questions*, June 21, 2010, Figure 1.

[223] CPUC A.10-03-012, Application of PG&E to Implement Assembly Bill 920 (2009) Setting Terms and Conditions for Compensation for Excess Energy Deliveries by Net Metered Customers, *Proposal of the Solar Alliance and Vote Solar Initiative for a Net Surplus Compensation Rate and Responses to Scoping Memo Questions*, June 21, 2010, Table 1, p. 3.
[224] CPUC Rulemaking R.06-02-012, Order Instituting Rulemaking to Develop Additional Methods to Implement the California Renewable Portfolio Standards Program, *Opening Comments of the California Wind Energy Association, the California Cogeneration Council, the Large-scale Solar Association, and the Solar Alliance on the Proposed Decision of ALJ Simon*, prepared by Crossborder Energy, October 6, 2008, pp. 3-4.
[225] D. Marcus, consultant and CAISO OASIS database, October 2010.
[226] Solar Anywhere website, hour-by-hour global irradiance data for 2007: https://www.solaranywhere.com/Public/SelectData.aspx
[227] Weather Warehouse website, U.S. Weather Service hour-by-hour cloud cover data for U.S. weather station sites. Data purchased for June 14, 2007 through September 5, 2007 period to capture all PG&E peak events when CAISO load was above 40,000 MW. Weather Warehouse reports the highest cloud cover percentage within the cloud cover interval registered in a given hour. For example, the first interval is 0 – 25 percent cloud cover. The Weather Warehouse dataset lists 25 percent cloud cover instead of the average value of 12.5 percent if cloud cover falls within the 0 – 25 percent range. Powers Engineering used the average cloud cover value for comparison with the actual ground-level global irradiance.
[228] A. Mills, R. Wiser – Lawrence Berkeley National Laboratory, *Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power*, September 2010, p. 11.
[229] Renewable Energy World, *Energy Storage, The Grid, and PV*, November 17, 2010.
[230] California Current, *Over-capacity concerns face new CPUC members*, January 28, 2011. "(PG&E spokesperson Brian) Swanson said that new plants like Oakley are needed to integrate renewable power into the grid as backups when the wind doesn't blow and the sun doesn't shine."
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[232] CEC, Chula Vista Energy Upgrade Project - Application for Certification (07-AFC-4) San Diego County, *Final Commission Decision*, June 2009.
[233] Ibid, pp. 29-30.
[234] CEC Title 24 webpage: http://www.energy.ca.gov/title24/
[235] Los Angeles Times, *California falls behind Massachusetts in energy efficiency*, October 20, 2011. See: http://latimesblogs.latimes.com/greenspace/2011/10/california-energy-efficiency.html.
[236] Ibid.
[237] Ibid.
[238] Ibid.
[239] Ibid.
[240] Ibid, p. 95.
[241] CPUC, *California Energy Efficiency Strategic Plan*, January 2011 Update, p. 87.
[242] See AB 1103 Commercial Building Energy Use Disclosure Program webpage, March 2012: http://www.energy.ca.gov/ab1103/.
[243] PG&E Market Integrated DSM Initiative – large commercial: http://www.pge.com/includes/docs/pdfs/about/rates/rebateprogrameval/programdescriptions/pge2007largecommercial0206.pdf
[244] http://www.sdge.com/construction/sustainable.shtml
[245] SDG&E, Sustainable Communities showcase webpage: http://www.sdge.com/environment/sustainablecommunities/projectsHome.shtml
[246] SDG&E Sustainable Communities Program Case Study, X-nth, Inc. (formerly TKG Consulting Engineers Inc.) office building retrofit, 2004.
[247] Austin Zero Energy Capable Homes Task Force, Memorandum, September 5, 2007. See: http://www.ci.austin.tx.us/council_meetings/wams_item_attach.cfm?recordID=7329. The Task Force defined a Zero Energy Capable Home as: "homes that are energy efficient enough to be net zero energy homes with the addition of on-site or its equivalent, energy generation. This level of energy efficiency is approximately 65% more efficient than homes built to the City of Austin Energy Code in effect in November, 2006."

[248] New York Times, *Off the Grid in the City*, February 1, 2012. See: http://www.nytimes.com/2012/02/02/greathomesanddestinations/a-texas-developer-attempts-to-upend-the-american-subdivision.html?pagewanted=all.
[249] See UC Davis West Village Backgrounder webpage, February 2012: http://westvillage.ucdavis.edu/press-kit/backgrounder.
[250] Berkeley Unified School District, *Solar Master Plan - Executive Summary*, November 2011, p. 2. See: www.heliosproject.net.
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[252] CPUC, *California Energy Efficiency Strategic Plan*, January 2011 Update, p. 87.
[253] CEC refrigerator webpage: http://www.consumerenergycenter.org/home/appliances/refrigerators.html
[254] PG&E refrigerator recycle page: http://www.appliancerecycling.com/weborder/rebatex.aspx?ProgramID=1
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[256] PG&E, *PG&E 2007-2016 Long-Term Procurement Plan*, Volume I, p. IV-13, reference to "Itron Potential Study."
[257] SEER is relative measure of energy efficiency. A SEER 20 air conditioning unit uses one-half the energy required by a SEER 10 unit to produce the same amount of cooling.
[258] S. Okura, M. Brost – RLW Analytics, Inc., and R. Rubin – SDG&E, *What Types of Appliances and Lighting Are Being Used in California Residences?*, 2005. In 2005, 53% of California residences had some form of cooling system.
[259] [(21 – 10)/21] – [(13 – 10/13)] = 0.52 – 0.23 = 0.29 (29 percent)
[260] Itron, *California Energy Efficiency Potential Study*, May 24, 2006, Chapter 11 - Emerging Technology Energy Efficiency Potential, p. 11-5 and p. 11-6.
[261] Public Power Daily, *SCPPA to Rollout 53-MW Storage Project*, January 27, 2010.
[262] Platts Purchasing Advisor, *HVAC: Centrifugal Chillers*, 2004.
[263] The term "kW per ton of cooling" is a measure of the electric energy necessary to operate a commercial or institutional chiller plant.
[264] One ton of cooling load is the amount of heat absorbed to melt one ton of ice in one day, which is equivalent to 12,000 Btu per hour.
[265] B. Erpelding, P.E., San Diego Regional Energy Office, *Ultra-efficient All-Variable Speed Chilled-Water Plants – Improving the energy efficiency of chilled-water plants through the utilization of variable speed and the optimization of entire systems*, HPAC Engineering, March 2006, pp. 35-43.
[266] B. Erpelding, P.E., San Diego Regional Energy Office (now California Center for Sustainable Energy) , *Ultra-efficient All-Variable Speed Chilled-Water Plants – Improving the energy efficiency of chilled-water plants through the utilization of variable speed and the optimization of entire systems*, HPAC Engineering, March 2006, pp. 35-43.
[267] Electric Power Research Institute, *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. – Executive Summary*, January 2009, Figure 2, p. 12.
[268] PG&E hot water heater page: http://www.pge.com/myhome/saveenergymoney/rebates/appliance/waterheater/index.shtml
[269] PG&E central air conditioner webpage: http://www.pge.com/myhome/saveenergymoney/savingstips/centralair/index.shtml
[270] PG&E eRebates webpage: http://www.pge.com/myhome/saveenergymoney/rebates/erebates/
[271] CPUC, *California Energy Efficiency Strategic Plan*, January 2011 Update, p. 18.
[272] Carrier product bulletin for SEER 10 model 38TKB036-34 3-ton air conditioning unit, 2004, p. 24.
[273] San Diego Union Tribune, Carrier central air conditioner advertisement, p. A-17, September 9, 2007.
[274] (4.0 kWh × 1,000 hours) –[(4.0 kWh × 1,000 hours) (10/21)] = 2,100 kWh saved. This is the electricity savings of 3-ton SEER 21 unit compared to a 3-ton SEER 10 unit over 1,000 hours of operation.
[275] Avalanche Mechanical (Carrier installer) quote to B. Powers for 3-ton SEER 21 central air conditioning and heating unit, September 4, 2007. Quote includes cost of new insulated ductwork.
[276] PG&E defines the summer peak period as May 1 to October 31, noon to 6 pm, excluding weekends and holidays. This is approximately 768 hours per year.
[277] (4 kWh × 768 hr) × [(10/13) – (10/21)] = 900 kWh. This is the electricity savings of a 3-ton SEER 21 unit compared to a SEER 13 unit over 768 hours of operation.
[278] See the discussion of PG&E's tiered residential rate structure in Chapter 9.

[279] CEC, Comparative *Costs of California Central Station Electricity Generation*, January 2010. Table B-4, p. B-5. Fixed cost of a new conventional 50 MW peaking gas turbine in 2009 is $303/kW-yr. Therefore, annual cost of 2 kW of peaking capacity: 2 kW × $303/kW-yr = $606/yr.
[280] CEC, California Building Climate Zones map: http://www.energy.ca.gov/maps/building_climate_zones.html
[281] PG&E, *PG&E 2007-2016 Long-Term Procurement Plan*, Volume I, p. IV-16.
[282] Sears Home Services, Heating & Air Conditioning Systems webpage, February 2012: http://www.searshomeservices.com/central-heating-air/improve. "The average service life of a whole house HVAC unit is 10-14 years."
[283] See CPUC Decision D.07-09-043: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/73172.htm
[284] CPUC Division of Ratepayer Advocates webpage: *DRA Continues to Fight Unearned Energy Efficiency Shareholder Bonuses*, January 2011: http://www.dra.ca.gov/DRA/Templates/Default.aspx?NRMODE=Published&NRNODEGUID=%7BEAC3EE8E-42F5-4D01-9342-D007FBC361D1%7D&NRORIGINALURL=%2FDRA%2Fenergy%2Fsim10.htm&NRCACHEHINT=Guest.
[285] CPUC Energy Division, *2006-2008 Energy Efficiency Evaluation Report – Draft*, April 15, 2010. See: http://www.dra.ca.gov/NR/rdonlyres/07ED3986-1D4F-455B-B3FF-B1AA96482022/0/200608DraftFinalEDEvaluationReport.pdf.
[286] Ibid, Table 23, p. 96.
[287] CPUC Division of Ratepayer Advocates – press release, *DRA Opposes $40 Million Bonus for PG&E*, November 15, 2010.
[288] Energy Trust of Oregon, *2010-2014 Strategic Plan*, December 18, 2009, p. 1. See: http://energytrust.org/library/plans/2010-14_Strategic_Plan_Approved.pdf
[289] Ibid, p. 3.
[290] Energy Trust of Oregon homepage, March 9, 20111: http://energytrust.org/about/
[291] Ibid, p. 3. Energy Trust invests about 74 percent of the three-percent fund. Another 16 percent goes to low-income housing and weatherization under the oversight of the Department of Housing and Community Services, and 10 percent goes to weatherization in K-12 schools under the direction of educational service districts.
[292] Ibid, p. 4.
[293] Chaptered version of SB 790, October 8, 2011: http://e-lobbyist.com/gaits/text/354030.
[294] www.sustainableindustries.com, *PACE rescue bill could get Republican help*, January 5, 2011.
[295] Pike Research, *PACE Financing Consumer Survey – Consumer Preferences and Attitudes about Property Assessed Clean Energy Financing Programs*, Q1 2011.
[296] www.sustainableindustries.com, *PACE rescue bill could get Republican help*, January 5, 2011.
[297] FHFA press release, *FHFA Statement on Certain Energy Retrofit Loan Programs*, July 6, 2010: "First liens established by PACE loans are unlike routine tax assessments and pose unusual and difficult risk management challenges for lenders, servicers and mortgage securities investors. The size and duration of PACE loans exceed typical local tax programs and do not have the traditional community benefits associated with taxing initiatives. FHFA urged state and local governments to reconsider these programs and continues to call for a pause in such programs so concerns can be addressed."
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[299] New York Times, *Recent Court Ruling Favors White House-Backed Home Energy Efficiency Program*, September 6, 2011.
[300] CoreLogic, *CoreLogic Reports 830,000 Completed Foreclosures Nationally in 2011, a Decrease of 24 Percent from One Year Ago*, February 8, 2012. See: http://www.corelogic.com/about-us/news/corelogic-reports-830,000-completed-foreclosures-nationally-in-2011,-a-decrease-of-24-percent-from-one-year-ago.aspx. "Approximately one-third of homes nationally are owned outright and do not have a mortgage."
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[306] See CPUC ruling in R.09-11-014 , January 10, 2012, p. 13: http://docs.cpuc.ca.gov/efile/RULINGS/157047.pdf.
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[310] Ibid, p. IV-20.
[311] Ibid, p. IV-16.
[312] Ibid. The non-firm program was replaced with the Base Interruptible Program (E-BIP).
[313] CEC Critical Peak Pricing webpage graphic: http://www.energy.ca.gov/research/esi/pricing/index.html
[314] Art Rosenfeld – CEC, *Demand Response Hardware and Tariffs: California's Vision and Reality*, presentation at PIER Demand Response Symposium, November 30, 2004, p. 6.
[315] SNL Financial, *California authorizes peak-day pricing for PG&E small-business customers*, February 25, 2010.
[316] PG&E webpage, Facts - What Is Peak Day Pricing?: http://www.pge.com/mybusiness/energysavingsrebates/demandresponse/peakdaypricing/facts/.
Peak day pricing adder for high demand (> 200 kW) commercial customers is $1.20/kWh.
[317] PG&E - Understanding Your Electric Charges webpage, updated January 1, 2012: http://www.pge.com/yourtiers/. http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/157640.pdf
[318] Ibid.
[319] PG&E Application A. 10-03-014, 2011 General Rate Case Phase 2 Prepared Testimony, Exhibit PG&E-1 – Revenue Allocation and Rate Design, Chapter 3, March 22, 2010, p. 3-2 and p. 3-8.
[320] The assumed productivity of fixed solar PV systems in the Bay Area is 1,900 kWh per year per kW_{ac} of capacity.
[321] CPUC Decision D.12-01-033, *Decision Approving Modified Bundled Procurement Plans*, January 12, 2012, pp. 20-21, p. 51. See: http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/157640.pdf . "Accordingly, to clarify the Commission's position, we expressly endorse the general concept that the utility obligation to follow the loading order is ongoing. The loading order applies to all utility procurement, even if pre-set targets for certain preferred resources have been achieved. . While hitting a target for energy efficiency or demand response may satisfy other obligations of the utility, that does not constitute a ceiling on those resources for purposes of procurement . . . It is ordered that (4) Utility procurement must comply on an ongoing basis with the Commission's loading order."
[322] CPUC, *California Energy Efficiency Strategic Plan,* January 2011 Update. See: http://www.cpuc.ca.gov/NR/rdonlyres/A54B59C2-D571-440D-9477-3363726F573A/0/CAEnergyEfficiencyStrategicPlan_Jan2011.pdf
[323] California Air Resources Board, *AB 32 Climate Change Scoping Plan*, December 2008, p. 44. See: http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm.
[324] CPUC Rulemaking R.10-05-006, *2010 Long-Term Procurement Proceeding Scoping Memo – Attachment 1, Standardized Planning Assumptions (Part 1) for System Resource Plans*, December 3, 2010, p. 17, p. 20, p. 23, p. 26, p. 29, p. 32, p. 35.
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[326] CPUC, *California Energy Efficiency Strategic Plan*, January 2011 Update, p. 53. "This initiative targets a 50 percent improvement in efficiency in the HVAC sector by 2020, and a 75 percent improvement by 2030."
[327] Ibid, p. 20, p. 30, p. 34, p. 41.
[328] CEC, *California Energy Demand 2010-2020 Adopted Forecast*, December 2009. Form 1.1 - Statewide California Energy Demand 2010-2020 Staff Revised Forecast Electricity Consumption by Sector (GWh), p. 37.
[329] CPUC, *California Energy Efficiency Strategic Plan*, January 2011 Update, p. 9. See: http://www.cpuc.ca.gov/NR/rdonlyres/A54B59C2-D571-440D-9477-3363726F573A/0/CAEnergyEfficiencyStrategicPlan_Jan2011.pdf
[330] CEC, *California Electricity Demand 2010-2020 Commission-Adopted Forecast*, Forms 1.1 and 1.1c, December 2009. See: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html. The approximate 277,000 GWh (276,509 GWh) statewide total is from Form 1.1c. The category-specific 2008 residential, commercial, industrial, and agriculture demand is from Form 1.1 and sums to 262,909 GWh. The difference between total 2008

demand and residential, commercial, industrial, and agricultural demand, which represents other loads including mining, telecommunications, communications, and utilities (TCU), and street lighting, is about 14,000 GWh.

[331] CPUC, *California Energy Efficiency Strategic Plan - Zero Net Energy Action Plan: Commercial Building Sector 2010-2012*, August 31, 2010, Appendix C, p. 34. See: http://www.cpuc.ca.gov/NR/rdonlyres/6C2310FE-AFE0-48E4-AF03-530A99D28FCE/0/ZNEActionPlanFINAL83110.pdf.

[332] CPUC, *California Energy Efficiency Strategic Plan*, January 2011 Update, p. 34. "In a 2004 Executive Order, Governor Schwarzenegger established the Green Buildings Initiative (GBI) which sets a goal of reducing energy use in state-owned buildings by 20 percent by 2015 (from a 2003 baseline) and encourages the private commercial sector to set the same goal."

[333] Assumes statewide average fixed PV output of 1,900 kWh per kW_{ac} of capacity. Source: NREL PV Watts V.1 Calculator: http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/. Output in San Francisco, Los Angeles, and San Diego within $\pm$ 3% of 1,900 kWh/kW_{ac}. Assumed dc-to-ac conversion efficiency = 80%.

[334] Ibid, Form 1.1c – California Energy Demand 2010-2020 Staff Revised Forecast Electricity Deliveries to End Users by Agency* (GWH), p. 39. 2008 statewide: 276,509 GWh, 2008 PG&E planning area = 105,795 GWh. (105,795 GWh/276,509 GWh) = 0.38 (38 percent).

[335] Ibid (2008 statewide electricity deliveries) and California Energy Consumption Database Management System – Electricity Consumption by County, 2008: http://www.ecdms.energy.ca.gov/. 2008 nine Bay Area counties = 57,316 GWh. (57,316 GWh/276,509 GWh) = 0.207 (21 percent).

[336] CAISO OASIS database, System Demand, July 8, 2008, 1 pm to 2 pm: 21,827 MW.

[337] CEC, *California Electricity Demand 2010 – 2020 Adopted Forecast*, December 2009, Form 1.5b. See: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html

[338] "Management" in this case refers to widespread adoption of air conditioner cycling as a peak load reduction measure.

[339] 2020 energy efficiency reduction targets in California Energy Efficiency Strategic Plan, January 2011 Update, are: 30 percent – residential, 25 percent – commercial, 25 percent – industrial. Assume overall peak load reduction of 25 percent compared to 2008 peak load for combined residential, commercial, and industrial energy efficiency measures.

[340] CEC, *Thermal Efficiency of Gas-Fired Generation in California, - Staff Paper*, August 2011, Table 2, p. 3.

[341] SNL Financial, *Update: Calpine details merchant survival strategy amid plummeting prices*, February 10, 2012.

[342] CPUC, *33% Renewable Portfolio Standard Implementation Analysis Preliminary Results*, June 2009, Table 2, p. 19.

[343] Ibid, p. 96.

[344] Ibid, p. 31. The CPUC PV sensitivity analysis assumed a thin-film PV capital cost of $\$3.70/W_{ac}$ with a cost-of-energy of $168/MWh. (p. 31) "Thus, the Solar PV Cost Reduction sensitivity results in the High DG Case having similar overall costs to the 33% RPS Reference Case and other renewable resource mixes that depend on central station renewable generation." The report defines High DG in this manner (p. 19) "Assumes limited new transmission corridors are developed to access additional renewable resources to achieve a 33% RPS. Instead, extensive, smaller-scale renewable generation is located on the distribution system and close to substations."

[345] CPUC, *Renewable Portfolio Standard Quarterly Report – 4th Quarter 2011*, February 2012, Appendix A. See: http://www.cpuc.ca.gov/NR/rdonlyres/3B3FE98B-D833-428A-B606-47C9B64B7A89/0/Q4RPSReporttotheLegislatureFINAL3.pdf.

[346] Ibid, Appendix A, p. 4.

[347] Craig Lewis – Clean Coalition, *Making Clean Local Energy Accessible Now*, PowerPoint presentation, California Foundation for the Economy and Environment workshop on distributed renewable generation, Sausalito, California, December 8-9, 2011, p. 8.

[348] See Palo Alto CLEAN Program webpage: http://www.cityofpaloalto.org/news/displaynews.asp?NewsID=1877&targetid=223.

[349] Greentech Media, *It's Official: Palo Alto, Calif. Has a Feed-In Tariff for PV*, March 6, 2012. See: http://www.greentechmedia.com/articles/read/Its-Official-Palo-Alto-Calif.-Has-a-Feed-In-Tariff-for-PV-/.

[350] BSW Solar, *Photovoltaics in Germany - Experiences with systems up to 250 kWp*, October 24, 2011, p. 15. Average Q3 2011 system price for 10 to 100 kW = 2.076 $€/W_{dc}$. The exchange rate as of February 2, 2012 is $1.31 = 1.00 €. Therefore 2.076 $€/W_{dc}$ = ($1.31/1.00 €)(2.076 $€/W_{dc}$) = $\$2.72/W_{dc}$.

[351] Assume 25 kW_{dc} small commercial rooftop PV at $\$2.70/W_{dc}$. Net capital cost, assuming 30 percent federal investment tax credit (ITC) and accelerated depreciation (gross capital cost - ITC × tax rate of 40%), would be

$1.13/$W_{dc}$. Assume production of 1,500 W_{ac}/yr per W_{dc} installed. Assume O&M cost of $20/kW-yr. Assume capital recovery factor of 0.0944 (7%, 20-year term). The levelized cost-of-energy = $0.084/kWh.

[352] BSW Solar, *Photovoltaics in Germany - Experiences with systems up to 250 kWp*, October 24, 2011, p. 15. Average Q3 2011 system price for 1 to 10 kW = 2.321 €/W_{dc}. The exchange rate as of February 2, 2012 is $1.31 = 1.00 €. Therefore 2.321 €/W_{dc} = ($1.31/1.00 €)(2.321 €/$W_{dc}$) = $3.04/$W_{dc}$.

[353] UPI.com, *Half of German solar firms could go under*, September 29, 2010.

[354] Ibid, p. 15.

[355] BSW Solar, *Photovoltaics in Germany - Experiences with systems up to 250 kWp*, October 24, 2011, p. 8.

[356] PRWEB, *Open Neighborhoods Community Solar Program*, September 6, 2011. "The new system, called AC Unison, reduces installation expenses by including built-in "microinverters" that make it economical to get started with a single panel.As part of the Open Neighborhoods Community Solar program, PermaCity is offering group discounts on the purchase of solar panel installations, with discounted pricing starting at $4.40/Watt for systems as small as 2kW, and further reduced pricing to $ 3.90/Watt for larger installations."

[357] $4.40/Wdc × 2 kWdc = $8,800/kWdc . Federal ITC reduces gross capital cost by 30 percent. Therefore net capital cost = $8,800/kWdc × (1 – 0.30) = $6,160. Annual capital cost recovery at 7 percent interest, 20 years = (0.0944/yr) × $6,160 = $582/yr. The micro-inverter has the same 25-yr guarantee as the solar panel. Assume O&M cost is $20/kW-yr. Therefore O&M cost = $20/kW-yr × 2 kW = $40/yr. Total annual 2 kW_{dc} PV system cost = $582/yr + $40/yr = $622/yr. Assume production is 1,500 kWh/kW_{dc}. Therefore total annual production = 1,500 kWh/kW_{dc} × 2 kW_{dc} = 3,000 kWh. Cost per kWh of production = $622/3,000 kWh = $0.207/kWh.

[358] Greentech Media, *Enphase S-1 Update: Microinverter Sales Soar*, February 25, 2012. See: http://www.greentechmedia.com/articles/read/Enphase-S-1-Update-PV-Microinverter-Sales-Soar/.

[359] Lawrence Berkeley National Laboratory, *An Analysis of the Effects of Residential Photovoltaic Energy Systems on Home Sales Prices in California*, Report LBNL-4476E, April 2011.

[360] Navigant, *Distributed Renewable Energy Assessment Final Report*, prepared for PIER Program California Energy Commission, August 11, 2009, p. 21.

[361] CEC, *2007 Integrated Energy Policy Report*, December 2007, pp. 155-156.

[362] Ibid, p. 155.

[363] CPUC Decision D.10-06-047, *Decision Adopting Requirements for Smart Grid Deployment Plans Pursuant to Senate Bill 17 (Padilla), Chapter 327, Statutes of 2009*, June 24, 2010, p. 2. See: http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/119902.pdf.
"As the Commission stated in Decision 09-09-029, modernizing the electric grid with additional two-way communications, sensors and control technologies, key components of a Smart Grid, can lead to substantial benefits for consumers. A Smart Grid can enable the integration of higher levels of renewable energy, energy storage, and, eventually, electric vehicles, at a lower cost to consumers."

[364] Central Intelligence Agency, CIA World Factbook 2011 – The Netherlands. See: https://www.cia.gov/library/publications/the-world-factbook/geos/nl.html. 2008 electricity consumption = 124.1 billion kWh, or 124,100,000 MWh. Average consumption: 124,100,000 MWh ÷ 8,760 hr/yr = 14,167 MW.

[365] E. Coster et al, *Integration Issues of Distributed Generation in Distribution Grids - This paper considers the probable operating problems and challenges in connecting distributed generation to low- and medium-voltage electric power grids*, published in Proceedings of the IEEE, Vol. 99, No. 1, January 2011, pp. 28-39.

[366] European Wind Energy Association, *Wind in Power – 2010 European Statistics*, February 2011, p. 4. A total of 2,237 MW of wind capacity was installed in The Netherlands at the end of 2010.

[367] E. Coster et al, *Integration Issues of Distributed Generation in Distribution Grids - This paper considers the probable operating problems and challenges in connecting distributed generation to low- and medium-voltage electric power grids*, published in Proceedings of the IEEE, Vol. 99, No. 1, January 2011, pp. 28-29.

[368] CEC distributed generation interconnection webpage: http://www.energy.ca.gov/distgen/interconnection/california_requirements.html

[369] CPUC Rulemaking R.08-08-009 – California RPS Program, Administrative Law Judge's Ruling on Additional Commission Consideration of a Feed-In Tariff, *Attachment A - Energy Division FIT Staff Proposal*, March 27, 2009, p. 15.

[370] CPUC Rulemaking R.08-08-009 – California RPS Program, Administrative Law Judge's Ruling on Additional Commission Consideration of a Feed-In Tariff, *Attachment A - Energy Division FIT Staff Proposal*, March 27, 2009, pp. 15-16.

[371] CEC, *2007 Integrated Energy Policy Report*, December 2007, Figure 1-11, p. 27.

[372] PG&E, *Smart Grid Deployment Plan*, 2011 – 2020, June 2011, Table 4-2, p. 59.
[373] E-mail from M. Martyak, PowerSecure (www.powersecure.com), to B. Powers, Powers Engineering, January 13, 2010. Approximate cost to upgrade older 100 MW distribution substation to full bidirectional flow, assuming four 25 MW load banks with four circuit breakers each (16 total), would be $400,000 to $450,000.
[374] Application No. 06-08-010, Matter of the Application of San Diego Gas & Electric Company (U-902-E) for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project, *Chapter 5: Prepared Rebuttal Testimony of SDG&E in Response to Phase 2 Testimony of Powers Engineering*, March 28, 2008, p. 5.21.
[375] Application No. 06-08-010, Matter of the Application of San Diego Gas & Electric Company (U-902-E) for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project, *Chapter 5: Prepared Rebuttal Testimony of SDG&E in Response to Phase 2 Testimony of Powers Engineering*, March 28, 2008, p. 5.20.
[376] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Application*, March 27, 2008, p. 3, p. 13. "SCE will place the PV systems on larger commercial rooftops with sufficient size and strength to accommodate approximately 1 to 2 MW of generation. The average cost of the solar PV facilities should be about $\$3.50/W_{dc}$."
[377] The dc-to-ac conversion factor is assumed to be 0.80. Therefore, $\$3,500/kW_{dc} \div 0.80 = \$ 4,375/kW_{ac}$.
[378] KEMA, *European Renewable Distributed Generation Infrastructure Study – Lessons Learned from Electricity Markets in Germany and Spain*, prepared for CEC, December 2011, p. 17: http://www.energy.ca.gov/2011publications/CEC-400-2011-011/CEC-400-2011-011.pdf.
[379] Ibid, p. 114.
[380] Ibid, p. 127.
[381] M. Zuercher-Martinson – Solectria Renewables, LLC, *Smart PV inverter benefits for utilities*, Photovoltaics World, November/December 2011, p. 18.
[382] Ibid.
[383] Ibid.
[384] Ibid.
[385] KEMA, *European Renewable Distributed Generation Infrastructure Study – Lessons Learned from Electricity Markets in Germany and Spain*, prepared for CEC, December 27, 2011, p. 35. See: http://www.energy.ca.gov/2011publications/CEC-400-2011-011/CEC-400-2011-011.pdf.
"DG plants with rated power of more than 100 kW must be equipped with remote telemetering and control capability to communicate their real-time output to the grid operator and allow for the TSO to send automatic power curtailment instructions to these generators. However, under current German law a PV project is only subject to this requirement if it has an individual PV panel rated 100 kW or larger (such as, the composite output of the PV project does not apply). However, the German legislature has recently passed legislation that, if signed by the executive branch, would essentially revoke this exemption for PV."
[386] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Application*, March 27, 2008, p. 6.
[387] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Testimony*, March 27, 2008, p. 44.
[388] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Application*, March 27, 2008, pp. 8-9.
[389] Ibid, p. 9.
[390] SCE Application A.08-03-015, *Solar Photovoltaic (PV) Program Testimony*, March 27, 2008, p. 27.
[391] Ibid, p. 6.
[392] CPUC Press Release – Docket A.08-03-015, *CPUC Approves Edison Solar Roof Program*, June 18, 2009.
[393] CPUC Press Release – Docket A.09-02-019, *CPUC Approves Solar PV Program for PG&E*, April 22, 2010.
[394] Navigant Consulting, *California Rooftop Photovoltaic (PV) Resource Assessment and Growth Potential by County - Pier Final Project Report*, prepared for CEC, September 2007, Appendix B, Table B.1 – Technical Potential by County.
[395] Source of 2009 population estimates: April 5, 2010 Moody's www.economy.com purchased population data for each Bay Area county.
[396] Dr. Donald Shoup, *The High Cost of Free Parking*, March 2005, published by American Planning Association, Chapter 1.
[397] Jim Trauth, Envision Solar, estimate of solar parking lot potential in San Diego County, e-mail to Bill Powers, June 13, 2007.
[398] RETI, *Renewable Energy Transmission Initiative RETI Phase 1B – Final Report*, January 2009, p. 6-25.

[399] Source of graphic: RETI, *Renewable Energy Transmission Initiative RETI Phase 1B – Draft Resource Report*, August 2008. Each pink square is 20 MW of distributed PV.
[400] EPA website, Siting Renewable Energy on Potentially Contaminated Land and Mine Sites: http://www.epa.gov/renewableenergyland/
[401] R. Ferguson – RETI Coordinator, *Renewable Energy Transmission Initiative (RETI) Criteria for Estimating Need - Discussion Draft*, November 11, 2010, p. 3, "private PV." See: http://www.energy.ca.gov/reti/steering/2010-11-18_meeting/documents/2010-11-10_Net_Short_Criteria-Ferguson.pdf
[402] CPUC Rulemaking R.08-08-009, Order Instituting Rulemaking to Continue Implementation and Administration of California RPS Program, *Decision Adopting Renewable Auction Mechanism*, December 16, 2010, p. 27. "Solar Alliance, Sierra Club, First Solar, FIT Coalition, LA Community College District, Vote Solar and others argue for a higher or no cap. For example, Solar Alliance recommends a cap of 2,000 MW; Sierra Club recommends 3,000 MW (with all FIT contracts included); FIT Coalition recommends 4,000 MW (with a minimum of 1,000 MW auctioned per year); LA Community College District and Vote Solar recommend no cap (i.e. unlimited)."
[403] LADWP, *Feed-In Tariff Demonstration Program – Board Briefing*, PowerPoint, January 25, 2012. See: http://www.ladwp.com/ladwp/cms/ladwp015039.pdf.
[404] PG&E total bundled + Direct Access demand 2009 = 85,459 GWh. Public utility demand within nine Bay Area counties in 2009 = 5,136 GWh. Total demand all types in nine Bay Area counties in 2009 = 55,817 GWh. Net PG&E demand in nine Bay Area counties = 55,817 GWh – 5,136 GWh = 50,681 GWh. Fraction of total PG&E demand in nine Bay Area counties = 50,681 GWh/85,459 GWh = 0.593 or 59.3 percent. Sources are: CEC, *California Energy Demand 2009-2020 Adopted Forecast*, December 2009, and CEC county demand database: http://ecdms.energy.ca.gov/elecbycounty.aspx
[405] Itron, *Impacts of Distributed Generation - Final Report*, prepared for CPUC, January 2010, p. 3-8, Table 3-4: All Solar Interconnections in Investor-Owned Utility (IOU) Territories. Itron identifies 299 MW of net metered PV of all types installed in PG&E territory as of September 2009, including installations that pre-date the CSI program, and identifies 622 MW remaining to be installed under the CSI program. Total is 921 MW.
[406] SB 32, Section 399.20(f). "The proportionate share (of 750 MW cap) shall be calculated based on the ratio of the electrical corporation's peak demand compared to the total statewide peak demand." PG&E demand is approximately one-third of statewide demand. For this reason, the PG&E allocation is assumed to be approximately 250 MW.
[407] CPUC Rulemaking R.08-08-009, Order Instituting Rulemaking to Continue Implementation and Administration of California RPS Program, *Decision Adopting Renewable Auction Mechanism*, December 16, 2010, p. 30. PG&E allocation is 420.9 MW.
[408] UCLA and Los Angeles Business Council, *Bringing Solar Energy to Los Angeles – An Assessment of the Feasibility and Impacts of an In-Basin Solar Feed-In Tariff Program*, July 2010.
[409] San Diego Regional Renewable Energy Study Group, *Potential for Renewable Energy in the San Diego Region*, August 2005. See Chapter 2, Solar Photovoltaic Electric: http://www.renewablesg.org/docs/Web/Ch2_Solar_PV_Electric.pdf
[410] Black & Veatch and E3, *Summary of PV Potential Assessment in RETI and the 33% Implementation Analysis,* PowerPoint presentation, Re-DEC Working Group Meeting, December 9, 2009.
[411] CEC PIER, *Combined Heat and Power Assessment – Final Consultant Report*, prepared by ICF International, April 2010, p. 20.
[412] K. Davidson, *Combined Heat and Power - Carlsbad Chamber of Commerce Sustainability Committee*, PowerPoint presentation, October 3, 2008.
[413] Ibid, p. 10.
[414] CEC PIER, *Combined Heat and Power Assessment – Final Consultant Report*, prepared by ICF International, April 2010.
[415] Natural gas CO_2 emission factor is 117 lb CO_2 per million Btu. The heat rate of a simple cycle combustion turbine is 9,000 to 10,000 Btu/kWh, or 9 to 10 million Btu/ MWh. This equates to a CO_2 emission rate of 1,050 to 1,170 lb CO_2 per MWh.
[416] Assumed heat rate of a combined cycle power plant is 7,000 Btu/kWh at baseload (full power) operating conditions. Multiplying by the natural gas CO_2 emission factor gives a CO_2 emission factor for combined cycle of approximately 820 lb CO_2 per MWh.
[417] California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, January 2010, Table C-5, p. C-12.

[418] R. Kehlhofer, et al, *Combined Cycle Gas & Steam Turbine Power Plants - 2nd Edition*, Figure 8-3, part load efficiency of GT and CC, p. 211. For example, a combined cycle unit with a baseload "high heating value" heat rate of 7,000 Btu/kWh would have a heat of 7,700 Btu/kWh, a 10 percent increase in fuel consumption on a unit basis, at 50 percent load.

[419] K. Davidson, *Combined Heat and Power - Carlsbad Chamber of Commerce Sustainability Committee*, PowerPoint presentation, October 3, 2008.

[420] Ibid.

[421] California Air Resources Board, *AB 32 Climate Change Scoping Plan*, December 2008, p. 44. See: http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm

[422] CEC PIER, *Combined Heat and Power Assessment – Final Consultant Report*, prepared by ICF International, April 2010, p. C-9.

[423] California Energy Consumption Database Management System, Electricity Consumption by County: http://www.ecdms.energy.ca.gov/elecbycounty.aspx

[424] *CEC,* California Energy Demand 2010 - 2020 Commission-Adopted Forecast*, December 2009. Form 1.1c. - Electricity Deliveries to End Users by Agency(GWH).*

[425] California Energy Consumption Database Management System, sum of electricity demand for nine Bay Area counties: http://www.ecdms.energy.ca.gov/elecbycounty.aspx

[426] Dr. Philip Perea, *An Assessment of Cogeneration for the City of San Francisco*, prepared for the Department of the Environment for the City and County of San Francisco, June 2007.

[427] Ibid, p. 57.

[428] NRG San Francisco Energy Center webpage: http://www.nrgthermal.com/Centers/Sanfran/whysf.htm

[429] Dr. Philip Perea, *An Assessment of Cogeneration for the City of San Francisco*, prepared for the Department of the Environment for the City and County of San Francisco, June 2007.

[430] B. Powers, San Diego Smart Energy 2020, October 2007, p.

[431] Bloom Energy webpage: http://www.bloomenergy.com/about/company-history/

[432] California Current, *Bloom Boxes*, Volume 9, Issue 3, January 21, 2011, p. 8.

[433] UTC webpage, PureComfort® Solution Applications. See: www.fuelcellmarkets.com/united_technologies_utc

[434] FERC Docket No. ER05-985-000, *Order Accepting Operating Memorandum – Trans Bay Cable LLC*, July 2005. FERC approved a 13.5 percent rate of return for Trans Bay Cable. CPUC argued that Trans Bay's proposed 13.5 percent return on equity was exorbitant and should be no greater than the 11-12 percent return that SCE and other companies across the country earn on their transmission projects.

[435] Tecogen case study brochure, CM-60 and CM-75 Cogeneration Modules – 1080 Chestnut Street, San Francisco, www.tecogen.com.

[436] Distributed Energy Magazine, *Dream Machine - An inverter connection to the grid lets CHP stay on when the lights go out*, November-December 2007.

[437] Tecogen press release, *Tecogen Receives Multiple Unit Order from Sacramento Utility for Groundbreaking Microgrid Demonstration Project*, September 2010.

[438] E-mail communication, M. DeAngelis, SMUD and B. Powers, Powers Engineering, March 1, 2012.

[439] California Energy Almanac, List of Biomass Power Plants in California: http://www.energyalmanac.ca.gov/renewables/biomass/index.html. SF Southeast WWT digester gas cogen project, 2.1 MW.

[440] CH2MHill, *Bioenergy Project Experience*, undated. See: http://www.ch2m.com/corporate/services/energy_management_and_planning/assets/ProjectPortfolio/Bioenergy.pdf. SF Oceanside WWT 1.1 MW digester gas cogen project.

[441] CEC, Renewable Energy Research – Biomass Landfill webpage: http://www.energy.ca.gov/research/renewable/biomass/landfill/index.html

[442] P. Kulkarni – CEC, *Biowaste CHP Systems Prospects and Barriers to a Community Energy Option*, presented at CADER Conference, April 29, 2010, p. 10. See: http://www.cader.org/documents2010/PramodKulkarni20100429.pdf

[443] P. Kulkarni - CEC, *Combined Heat and Power Potential at the California Wastewater Treatment Plants – Draft Staff Report*, July 2009, p. 10.

[444] California Center for Sustainable Energy, *San Diego Gets Clean Energy*, December 14, 2010.

[445] PG&E press release, *PG&E and Bioenergy Solutions Turn the Valve on California's First "Cow Power" Project - Renewable Natural Gas Made From Animal Waste to Flow Through PG&E's Pipelines*, March 4, 2008. See:

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446 M. Uchin - PG&E, *Expanding Delivery of Renewable Natural Gas (Biogas) to Customers in Northern California*, presentation, June 16, 2010.
447 K. Brennan – PG&E, *Biomethane Injection Into Gas Utility Pipelines,* National Biomethane Summit, June 23, 2009, p. 7.
448 H. Snyder – Sempra Energy Utilities, *Renewable Biogas: Pipeline Biomethane*, NARUC Staff Subcommittee on Gas, July 18, 2010, p. 9.
449 SMUD news release, *SMUD to purchase green gas from Texas*, April 15, 2009. "SMUD will enter into a 15-year contract with Shell Energy for 6 billion British thermal units (Btu) of gas per day." 6 billion Btu per day equals 6 million cubic feet per day of biomethane, assuming a biomethane heating value of 1,000 Btu per cubic foot.
450 T. John, P.E., Tommy John Engineering, Inc, *Using and Measuring the Combined Heat and Power Advantage*, presented at American Institute of Chemical Engineers, Spring National Meeting, March 2010, p. 5. of large and small CHP is 4,200 Btu/kWh. 6 billion Btu per day ÷ 4,200 Btu/kWh = 1.43 million kWh per day. This equals 1,430 MWh per day. 1,430 MWh per day ÷ 24 hours per day = 59.6 MW.
451 California Legislative Counsel's Digest, text of AB 1613, November 15, 2007.
452 AB 1150 (Perez), Self-Generation Incentive Program: www.aroundthecapitol.com/billtrack/Bills/AB_1150.
453 http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=CA23F&state=CA&CurrentPageID=1
454 See: http://www.cpuc.ca.gov/PUC/energy/Renewables/index.htm.
455 CPUC Division of Ratepayer Advocates, *California's Solar Paradox*, Figure 4, p. 18. See: http://www.dra.ca.gov/NR/rdonlyres/5A0E254D-47E0-4625-BACF-F1049CEAB924/0/ParadoxPaperFinal_v2.pdf.
456 MPR is the cost-of-energy for a new natural gas-fired combined cycle that includes a greenhouse gas emissions adder. See CPUC MPR website: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr
457 CPUC MPR webpage, 2009 MPR Documents, 2009 MPR Model, Appendix F – Non-Gas Inputs: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr
458 See CPUC RPS Cost Containment webpage: http://www.cpuc.ca.gov/PUC/energy/Renewables/SB1036implementation.htm.
459 CPUC press release, *CPUC Staff Reports Solar Program Doubled Installations in 2008 Compared to Prior Year*, January 28, 2009. See: http://docs.cpuc.ca.gov/word_pdf/NEWS_RELEASE/96627.pdf.
460 CEC, *Ivanpah Solar Electric Generating System – Final Staff Assessment and Draft Environmental Impact Statement*, November 4, 2009, p. 4-62. See: http://www.energy.ca.gov/2008publications/CEC-700-2008-013/CEC-700-2008-013-FSA.PDF.
461 SB 1036 as chartered: http://info.sen.ca.gov/pub/07-08/bill/sen/sb_1001-1050/sb_1036_bill_20071014_chaptered.pdf.
462 California Public Utilities Code 399.15: http://law.onecle.com/california/utilities/399.15.html.
463 2009 MPR webpage:. http://docs.cpuc.ca.gov/PUBLISHED/FINAL_RESOLUTION/111386.htm.
464 The capacity factor of the Mojave project is estimated at 27 percent by the CEC. See Sept. 15, 2010 Final Commission Decision, p. 88: http://www.energy.ca.gov/sitingcases/abengoa/documents/index.html. Therefore, annual electricity production = 0.27 x 8,760 hr/yr × 250 MW = 591,300 MWh/yr. Electricity production over 25-year PPA term = 25 yr × 591,300 MWh/yr = 14,782,500 MWh. The above MPR cost of the PPA over the 25-year term is $1.25 billion. Therefore the unit cost above MPR = $1,250,000,000 ÷ 14,782,500 MWh = $84.56/MWh. The 2009 MPR for a 25-year PPA with a project start year of 2014 is $116.36/MWh. Therefore the total cost per MWh of the Mojave PPA would be: $116.36/MWh + $84.56/MWh = $200.92/MWh.
465 CPUC PPA authorization for Genesis, August 12, 2010: http://docs.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/122173.pdf.
466 Project Finance International, *Sun shines on Genesis*, September 7, 2011. "The PPA price varies depending on the cooling technology used. US $174.10 per MWh for dry cooling technology and US $162.50 per MWh for wet cooling technology adjusted for time of day pricing."
467 CPUC PPA authorization for Sunpower" High Plains Ranch II, February 20, 2009: http://docs.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/97784.pdf.
468 CPUC PPA authorization for Sunpower High Plains Ranch III, November 19, 2010: http://docs.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/126951.pdf.

[469] New York Times, *A Gold Rush of Subsidies in Clean Energy Search*, November 11, 2011. See: http://www.nytimes.com/2011/11/12/business/energy-environment/a-cornucopia-of-help-for-renewable-energy.html?_r=1&pagewanted=all. "PG&E, and ultimately its electric customers, will pay NRG $150 to $180 a megawatt-hour, according to a person familiar with the project, who asked not to be identified because the price information was confidential."

[470] Forbes, *California Approves High-Priced Mojave Solar Project Over Objections*, November 10, 2011. See: http://www.forbes.com/sites/toddwoody/2011/11/10/california-approves-high-priced-mojave-solar-project-over-objections/. "The PPA unnecessarily saddles ratepayers with extraordinary above-market costs – $1.25 billion," said Commissioner Mike Florio, who voted against the contract at Thursday's meeting. "We could probably get almost 500 megawatts of renewable energy for the price we're paying for this 250 megawatts."

[471] CPUC, *Renewable Portfolio Standard Quarterly Report – 4th Quarter 2011*, February 2012, Appendix A, p. 4. See: http://www.cpuc.ca.gov/NR/rdonlyres/3B3FE98B-D833-428A-B606-47C9B64B7A89/0/Q4RPSReporttotheLegislatureFINAL3.pdf.

[472] Ibid.

[473] See CPUC Summary of Feed-In Tariffs webpage: http://www.cpuc.ca.gov/PUC/energy/Renewables/feedintariffssum.htm.

[474] 2011 MPR pricing: http://www.cpuc.ca.gov/PUC/energy/Renewables/Feed-in+Tariff+Price.htm. .

[475] CPUC Net Surplus Compensation webpage: http://www.cpuc.ca.gov/PUC/energy/DistGen/netsurplus.htm. .

[476] CPUC D.11-06-016, *Decision Adopting Net Surplus Compensation Rate Pursuant to Assembly Bill 920 and the Public Utility Regulatory Policies Act of 1978*, June 9, 2011. "Finding of Fact (16) The only generation the utility avoids when an NEM customer provides surplus generation is reduced electricity procurement from the short-term wholesale market."

[477] PG&E AB 920 Net Surplus Compensation Facts webpage, March 4, 2012: http://www.pge.com/myhome/saveenergymoney/solarenergy/afterinstalling/ab920/. "Based on current market prices, the rate would be approximately 4 cents per kWh."

[478] SB 32: http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0001-0050/sb_32_bill_20091011_chaptered.html

[479] Code 399.20: http://law.onecle.com/california/utilities/399.20.html.

[480]AB 1613: http://www.leginfo.ca.gov/pub/07-08/bill/asm/ab_1601-1650/ab_1613_bill_20071014_chaptered.pdf.

[481] Power Magazine, *Regulatory Options for Feed-In Tariffs*, December 2010.

[482] California Cogeneration Council, *Pre-Workshop Opening Comments of California Cogeneration Council*, June 4, 2004, CPUC R. 04-04-025, Rulemaking to Promote Consistency in Methodology and Input Assumptions in Commission Applications of Short-run and Long-run Avoided Costs, Including Pricing for Qualifying Facilities. "The 1978 Public Utilities Regulatory Policies Act (PURPA) sought to reduce the country's dependence on oil through the development of new resources for electric generation, including renewable resources (solar, wind, biomass, geothermal, and small hydro) and the more efficient use of oil and gas in cogeneration projects. PURPA's key reforms included a requirement that the utilities must purchase the power output of qualifying cogeneration and other small power production facilities (referred to as "qualifying facilities" or "QFs") – a key step designed to encourage the development of QFs by ensuring a buyer for QF power. PURPA also required the utilities to purchase QF power at the purchasing utility's avoided cost–that is, at the cost that the utilities would have incurred themselves to produce or purchase the same energy and capacity."

[483] Ibid.

[484] DWR Energy Contracts webpage, March 2012: http://www.cers.water.ca.gov//energy_contracts.cfm. .

[485] Department of General Services, *Energy Efficient State Property Revolving Fund Loan Program – Executive Summary*, December 2011, See: http://www.documents.dgs.ca.gov/dgs/PIO/Releases/2011/111222arra.pdf.

[486] See individual project descriptions on CEC power plant webpage: http://www.energy.ca.gov/sitingcases/alphabetical.html

[487] CEC, *Russell City Energy Center Presiding Member's Preliminary Decision*, August 2007, p. 7. "Amended project will be designed to operate in load following mode (not baseload). CEC, *Oakley Generating Station Preliminary Staff Assessment*, December 2010, p. 1-3. "Expected capacity factor is 60 to 80 percent."

[488] CEC, *Marsh Landing Generating Station Final Decision*, August 2010, p. 4. "The MLGS will be capable of operating at a maximum capacity factor of 20 percent." CEC, *Mariposa Energy Center Staff Assessment*, November 2010, p.4.1-15. "However, the applicant expects the proposed MEP combustion turbines to actually run only approximately 600 hours per year with 200 startup and shutdown events annually, based on MEP's review of data from 2004 on California simple-cycle power plants greater than 50 MWp." p. 5.4-3. "The applicant expects to operate the MEP approximately 600 hours per year, or about 7% of the year."

[489] CEC, *Comparative Costs of California Central Station Electricity Generation*, January 2010, p. 54, Table 14. Small simple cycle (Mariposa) = $1,292/kW, advanced simple cycle (Marsh Landing) = $827/kW, combined cycle duct-fired (Russell City and Oakley) = $1,080/kW.
[490] These charges are known as "capacity payments." Russell City and Oakley are combined cycle plants that would be expected to operate regularly in a load-following pattern. Marsh Landing, and Mariposa would operate infrequently, primarily during summer high temperature periods, as peaking power plants.
[491] CPUC Decision D.06-07-029, *Opinion on New Generation and Long-Term Contract Proposals and Cost Allocation*, July 20, 2006, pp. 3-4. "We therefore conclude that immediate and affirmative Commission action is required to assure construction of adequate new capacity during the time in which we are transitioning to more robust and durable market institutions. The only complete solution . . . make the IOUs the entities responsible for acquiring new generation capacity, on a temporary basis, for bundled and unbundled customers alike."
[492] CEC, *Comparative Costs of California Central Station Electricity Generation,* January 2010, p. B-5, Table B-4. Fixed cost of small simple cycle (200 MW Mariposa) = $303/kW-yr; conventional simple cycle (760 MW Marsh Landing) = $283/kW-yr, and combined-cycle with duct firing (600 MW Russell City and 624 MW Oakley) = $259/kW-yr. Total yearly fixed costs for all four units are $593 million per year over twenty years.
[493] Assumes commercial rooftop PV at $3.50/$W_{dc}$. Net capital cost, assuming 30 percent investment tax credit and accelerated depreciation, would be $1.47/$W_{dc}$. Net capital cost is $1.84/$W_{ac}$, or $1.84 million per MW_{ac}, assuming 80% dc-to-ac conversion. $600 million per year ÷ $1.84 million per MW_{ac} = 326 MW_{ac} per year.
[494] William Marcus, JBS Energy, Inc. on behalf of TURN, *MPR Capacity Factor*, PowerPoint presentation given at CPUC MPR workshop, R.06-02-012, March 27, 2008.
[495] CEC, *Comparative Costs of California Central Station Electricity Generation,* January 2010, p. C-12. Table C-5: Combined Cycle Facility Capacity Factors. Average capacity factor for 15 California combined cycle plants in 2008 is 65 percent.
[496] CPUC assumes 65% capacity factor for combined cycle units in *Inputs and Assumptions to 33% Renewables Portfolio Standard Implementation Analysis,* prepared by E3 for CPUC, July 2009.
[497] CEC, *Thermal Efficiency of Gas-Fired Generation in California – Staff Paper*, August 2011, Table 2, p. 3. 2010 capacity factor of combined-cycle plants built since 2000 = 50.3 percent.
[498] CPUC MPR webpage, 2009 MPR Documents, 2009 MPR Model, "Install_Cap" tab: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr.
[499] CEC, *Comparative Costs of California Central Station Electricity Generation* , January 2010, Appendix B.
[500] Ibid, Tables 11 - 13.
[501] CPUC MPR webpage, 2009 MPR Documents, 2009 MPR Model: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr.
[502] CPUC assumes 65 percent capacity factor for combined cycle units in *Inputs and Assumptions to 33% Renewables Portfolio Standard Implementation Analysis,* prepared by E3 for CPUC, July 2009.
[503] CEC, *Thermal Efficiency of Gas-Fired Generation in California – Staff Paper*, August 2011, Table 2, p. 3. 2010 capacity factor of combined-cycle plants built since 2000 = 50.3 percent.
[504] CEC, *Comparative Costs of California Central Station Electricity Generation* , January 2010, Table 1, Table 5, Figure A-8. A 500 MW unfired merchant combined cycle plant with a 75 percent capacity factor is the average case in the CEC report. Note – the dates shown in the table, 2009 and 2018, are commercial start dates.
[505] CPUC Application A.09-09-021, Application by PG&E for Approval of 2008 Long-Term Request for Offers Results, *Alternate Proposed Decision of Commissioner Bohn*, November 2, 2010.
[506] See Table 7-1. Base load transmission line losses are 5 percent. The cost-of-energy from a remote solar thermal plant is $202/MWh. Therefore the value of avoided transmission line losses = 0.05 × $202/MWh = $10.1/MWh.
[507] Itron, *CPUC Self-Generation Incentive Program—Ninth-Year Impact Evaluation Report – Final Report,* submitted to PG&E, June 2010, Table 5-14, p. 5-32. PG&E peak hour fixed PV capacity factor in 2009 was 54 percent, July 14, 2009, 4 pm to 5 pm.
[508] CPUC R.06-02-12, Rulemaking to Develop Additional Methods to Implement the California Renewables Portfolio Standard Program, *Pre-Workshop Comments of GreenVolts, Cleantech America, and Community Environmental Council on the 2008 Market Price Referent*, March 6, 2008, p.15. Table - E3 Model T&D Values (levelized 20-year in $2008).
[509] CPUC MPR webpage, 2009 MPR Documents, 2009 MPR Model, Appendix F – Non-Gas Inputs: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr. Year 1 heat rate is 6,879 Btu/kWh (6.879 MMBtu/MWh). Natural gas CO_2 emission rate is 117 lb CO_2/MMBtu. Therefore CO_2 emission rate is 6.879 MMBtu/MWh x 117 lb

CO_2/MMBtu = 805 lb CO_2/MWh (0.40 ton CO_2/MWh). Cost of greenhouse gas adder in MPR is 0.40 ton CO_2/MWh x \$15/ton CO_2 = \$6/MWh.

[510] Application 10-03-012, Application of PG&E to Implement Assembly Bill 920 (2009) Setting Terms and Conditions for Compensation for Excess Energy Deliveries by Net Metered Customers, *Proposal of the Solar Alliance and Vote Solar Initiative for a Net Surplus Compensation Rate and Responses to Scoping Memo Questions*, June 21, 2010, p. 3. **"**The avoided line loss factor and avoided T&D costs are determined by applying the representative solar output profiles to the hourly line loss factors and avoided T&D costs included in the Commission's most recently adopted avoided cost model for energy efficiency resources (the E3 avoided cost model)."

[511] CEC, *Comparative Costs of California Central Station Electricity Generation* , January 2010, Table 1, Table 5. Resource is 500 MW unfired merchant combined cycle plant.

[512] New York Times, *Solar Panel Maker Moves Work to China*, January 14, 2011. "World (solar panel) prices have fallen as much as two-thirds in the last three years — including a drop of 10 percent during last year's fourth quarter alone."

[513] UPI.com, *Half of German solar firms could go under*, September 29, 2010.

[514] T. Beach, P. McGuire, Crossborder Energy, *Re-evaluating the Cost-Effectiveness of Net Energy Metering in California*, December 20, 2011, Figure 1, p. 3.

[515] See: http://www.cpuc.ca.gov/PUC/energy/Renewables/FAQs/05REcertificates.htm. "In D.07-01-018, the CPUC determined that facilities that serve onsite load (e.g. facilities receiving incentives from the California Solar Initiative or Self-Generation Incentive Program) own their RECs. In other words, the facility owner owns the RECs, and they are not transferred to the utility. That means that a facility owner can either make green claims (e.g. "our company is powered by solar") if it retains the RECs, or the owner can seller the RECs so another entity can make green claims. The CPUC does not regulate who the facility owner sells its RECs to."

[516] See: http://docs.cpuc.ca.gov/word_pdf/AGENDA_DECISION/129354.pdf.

[517] Ibid.

[518] Renewable Energy World, *California Net Metering Bill Signed by Governor Schwarzenegger*, March 1, 2010. "AB 510 raises the net metering cap to 5% and will help meet projected demands received under the California Solar Initiative program."

[519] See: http://www.cpuc.ca.gov/PUC/energy/DistGen/vnm.htm.

[520] See: http://www.aroundthecapitol.com/Bills/SB_843/20112012/.

[521] CPUC R.06-02-12, Rulemaking to Develop Additional Methods to Implement the California Renewables Portfolio Standard Program, *Pre-Workshop Comments of GreenVolts, Cleantech America, and Community Environmental Council on the 2008 Market Price Referent*, March 6, 2008, p.15. Table - E3 Model T&D Values (levelized 20-year in \$2008). Baseload T&D avoided cost for Bay Area zones ranges from \$1.93 to 8.03 per MWh.

[522] The market price of power is set by the generating unit with the highest variable cost in any given hour. However, the predominant variable cost is fuel cost.

[523] German Federal Ministry for the Environment, Nature Conservation, and Nuclear Safety, *Cost and benefit effects of renewable energy expansion in the power and heat sectors,* June 2010. Merit order effect of renewable energy estimated at 3.6 to 4 billion Euros in 2009. 1 Euro = 1.334 dollars as of January 16, 2011. Therefore 3.6 to 4 billion Euros = 4.8 to 5.3 billion dollars.

[524] Yale Global, *Germany Leads With Its Goal of 100 Percent Renewable Energy*, September 7, 2010. Approximately 9,800 MW of solar and 25,800 MW of wind resources were online in Germany by the end of 2009.

[525] UPI.com, *German renewable industry booming*, March 24, 2010.

[526] International Energy Agency, Statistics Germany 2008. Final 2008 consumption of electricity = 526,000 GWh. See: http://www.iea.org/stats/electricitydata.asp?COUNTRY_CODE=DE

[527] Photon International, *The bigger solar picture*, September 2010.

[528] California Independent System Operator OASIS website: http://oasis.caiso.com/mrtu-oasis/home.jsp?doframe=true&serverurl=http%3a%2f%2farptp10%2eoa%2ecaiso%2ecom%3a8000&volume=OASIS

[529] CEC, 2009 *Integrated Energy Policy Report*, January 2010, p. 52.

[530] Ibid, p. 78.

[531] The 12 percent estimate is based on using 32,000 GWh of renewable energy production, the mid-point of the 27,000 to 37,000 GWh CEC 2009 IEPR estimate (p. 78) of renewable energy production.

[532] (California market size/German market size) x (California renewable %/German renewable %) x 2009 German merit order consumer savings = (1/2) x (12/16) x \$5 billion per year = \$1.9 billion per year.

[533] $2 billion per year ÷ 12 percent = ~$170 million per year per percent of renewable energy.
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[535] $170 million per year ÷ 1,150 1 MW projects = $148,000 per MW per year.
[536] The net present value multiplier for a 20-year period, assuming 7 percent interest, is 10.594. The NPV in 2011 dollars of $150,000 per year for 20 years = $150,000 x 10.594 = $1,591,100.
[537] Net capital cost, assuming gross installed rooftop PV cost of $3.50/W$_{dc}$, 30 percent investment tax credit, and accelerated depreciation, would be $1.47/W$_{dc}$. Net capital cost is $1.84/W$_{ac}$, or $1.84 million per MW$_{ac}$, assuming 80% dc-to-ac conversion. See Appendix H for a sample calculation of the net effect of tax benefits on capital cost.
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[557] Ontario Power Authority FIT website: http://fit.powerauthority.on.ca/Page.asp?PageID=751&SiteNodeID=1107&BL_ExpandID=260
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[630] CEC, *Comparative Costs of California Central Station Electricity Generation*, January 2010, Table B-4, p. B-5.
[631] This present value assumes the initial peaking gas turbine cost of $303/kW-yr includes an inflation adjustment over time such that the inflation-adjusted cost in Year 15 of a 15-year amortization period would be equivalent to $303/kW-yr in 2011 dollars.
[632] Renewable Energy Systems Battery Store, Surrette 2V/2491 solar battery 2-KS-33PS, 20 hour capacity – 3.53 kWh, $780 per battery. Ten batteries: 3.53 kWh × 10 = 35.3 kWh, $780 × 10 = $7,800. "The Rolls Surrette 2-KS-33PS solar deep cycle (thick-plate lead-acid) battery is designed specifically for renewable energy applications and is backed by a 10 year warranty with an expected lifespan of 15-20 years." See: http://store.renewableenergysys.com/browse.cfm/battery-surrette-2v-2491-solar-battery-2-ks-33ps/4,42.html
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[641] e-mail communication between T. Walker, S&C Electric Co., and B. Powers, Powers Engineering, December 7, 2011. Assume capital cost of CES with one hour of storage is $1,500 to $2,200/kW. Half of this cost is for CES hardware, the other half for lithium batteries. Therefore conservastive capital cost for the CES-only is $2,200/kW ÷ 2 = $1,100/kW.
[642] Renewable Energy Systems Battery Store, Surrette 2V/2491 solar battery 2-KS-33PS, 20 hour capacity – 3.53 kWh, $780 per battery. Ten batteries: 3.53 kWh × 10 = 35.3 kWh, $780 × 10 = $7,800. "The Rolls Surrette 2-KS-33PS solar deep cycle (thick-plate lead-acid) battery is designed specifically for renewable energy applications and is backed by a 10 year warranty with an expected lifespan of 15-20 years." See: http://store.renewableenergysys.com/browse.cfm/battery-surrette-2v-2491-solar-battery-2-ks-33ps/4,42.html. $7,800 ÷ 35.3 kWh = $223/kWh. Assuming a rated discharge (kW) to storage (kWh) ratio of approximately one-to-one, battery cost would be less than $300/kW. Therefore an upper-end capital cost for 3 hours of storage would be: 3 × $300/kW = $900/kW.
[643] $1,100/kW (CES) + $900/kW (3 hours thick-plate lead-acid battery storage) = $2,000/kW.
[644] The fixed cost of new peaking gas turbine capacity is $303/kW-yr. The amortized cost of the CES unit with 3 hours of thick-plate lead-acid battery storage would be, at 7%, 20 years, $2,000/kW x 0.0944/yr = $189/kW-yr.

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[655] Environment California, *Solar Water Heating - How California Can Reduce Its Dependence on Natural Gas*, p. 9.
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[661] US Department of Energy, *Absorption Heat Pumps*, February 9, 2011. See: http://www.energysavers.gov/your_home/space_heating_cooling/index.cfm/mytopic=12680
[662] www.arizonaenergy.org, small ammonia refrigerator: http://www.arizonaenergy.org/AltEnergyClub/SMALL%20AMMONIA%20REFRIGERATOR.htm
[663] American Council for an Energy-Efficient Economy, *Impact of Energy Efficiency and Renewable Energy on Natural Gas Markets in the Pacific West*, January 2006, p. 8, and Table 6, p. 9. Reduction in natural gas usage in WA, OR, and CA of 1,054 MMcf in 2010 leads to annual savings of at least $5 billion.
[664] Ibid, Figure 5, p. 10.
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[666] CPUC, *California Strategic Energy Efficiency Plan*, January 2011 Update, Section 2, p. 9.
[667] http://www.eoearth.org/article/Altamont_Pass,_California
[668] Ibid.
[669] 1,100,000 MWh/yr ÷ (576 MW × 8,760 hr/yr) = 0.218.
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[671] Jason Dearen, San Jose Mercury News, 5 December 2010. *Wind turbines to be upgraded in Altamont Pass.* Available at http://www.biologicaldiversity.org/news/center/articles/2010/san-jose-mercury-news-12-06-2010.html
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[673] Source of actual 2008 monthly 150 MW Shiloh I electricity production data: U.S. DOE, Energy Information Administration, 2008 Form 923 Monthly Time Series. Total electricity production in 2008 = 472,057 MWh. Annual capacity factor = [472,057 MWh/yr ÷ (150 MW)(8,760 hr/yr)] = 0.359 (36 percent). See Figure 7-4.
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[675] Source of graphic: RETI, *Renewable Energy Transmission Initiative RETI Phase 1B – Draft Resource Report*, August 2008.

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Bay Area Smart Energy 2020 - Appendices

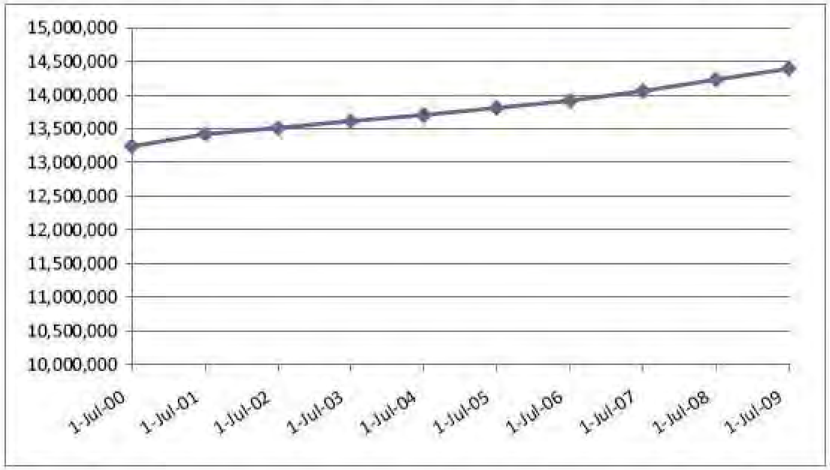
Appendix A

Population Growth in PG&E Service Territory, 2000 – 2009

County	Bay Area	In PG&E	1-Jul-00	1-Jul-01	1-Jul-02	1-Jul-03	1-Jul-04	1-Jul-05	1-Jul-06	1-Jul-07	1-Jul-08	1-Jul-09
Alameda	Y	A	1,450,220	1,468,918	1,460,576	1,450,968	1,441,781	1,436,453	1,438,193	1,449,020	1,470,326	1,491,482
Alpine	N	S	1,205	1,175	1,195	1,172	1,182	1,123	1,158	1,144	1,057	1,041
Amador	N	A	35,173	35,700	36,506	36,860	37,213	37,788	38,072	38,480	37,980	37,876
Butte	N	A	203,926	206,384	209,319	211,584	213,173	214,831	216,933	217,741	219,503	220,577
Calaveras	N	A	40,696	41,433	42,583	44,007	44,852	45,688	46,524	46,852	46,944	46,731
Colusa	N	A	18,829	19,042	19,264	19,579	20,219	20,541	20,889	21,100	21,155	21,321
Contra Costa	Y	A	953,192	971,487	980,446	987,662	992,747	999,271	1,001,303	1,010,542	1,025,464	1,041,274
El Dorado	N	S	157,134	160,848	164,675	167,436	170,486	173,500	174,995	175,752	177,009	178,447
Fresno	N	S	801,444	812,426	828,245	844,194	857,162	867,438	878,024	889,888	903,133	915,267
Glenn	N	A	26,451	26,487	26,705	27,071	27,193	27,452	27,714	27,862	28,127	28,299
Humboldt	N	A	126,403	127,002	127,779	128,219	128,694	128,943	129,033	128,564	128,852	129,623
Kern	N	S	663,484	674,028	689,204	706,963	726,029	747,315	768,209	784,687	797,145	807,407
Kings	N	S	129,774	132,453	134,681	138,714	142,151	143,178	145,168	147,622	148,746	148,764
Lake	N	A	58,551	60,321	61,674	62,692	63,390	64,143	64,623	64,644	65,092	65,279
Madera	N	A	123,566	125,423	127,841	132,017	136,516	139,672	142,865	145,223	147,577	148,632
Marin	Y	A	247,614	247,958	246,332	245,030	243,677	244,024	244,336	246,100	248,345	250,750
Mariposa	N	A	17,143	17,106	17,202	17,585	17,656	17,714	17,896	17,963	17,960	17,792
Mendocino	N	A	86,396	86,614	86,911	87,415	87,092	86,803	85,959	85,560	85,786	86,040
Merced	N	S	212,122	217,937	223,666	228,993	233,529	237,901	240,516	243,083	244,356	245,321
Monterey	N	A	403,065	407,065	409,210	410,419	408,867	405,090	401,374	402,116	405,660	410,370
Napa	Y	A	124,545	126,731	128,584	129,800	130,007	129,859	130,818	131,949	133,591	134,650
Nevada	N	S	92,503	93,594	94,412	95,195	95,974	96,554	96,772	96,942	97,297	97,751
Placer	N	S	251,274	264,221	277,833	291,883	304,386	314,619	324,213	331,870	341,041	348,552
Plumas	N	S	20,764	20,825	20,861	20,929	20,963	20,957	20,704	20,606	20,359	20,122
San Benito	N	A	53,827	54,752	55,217	55,376	55,090	54,930	54,468	54,505	54,797	55,058
San Francisco	Y	A	777,360	784,631	779,281	775,046	773,284	777,660	786,149	799,185	808,001	815,358
San Joaquin	N	S	567,968	591,000	608,367	625,236	640,964	654,451	659,897	665,246	668,753	674,860
Obispo	N	A	247,878	251,499	252,932	254,240	256,095	257,567	259,366	261,706	265,134	266,971
San Mateo	Y	A	708,272	706,634	699,043	694,437	692,033	692,199	692,802	697,339	708,100	718,989
Santa Barbara	N	A	399,784	401,456	402,079	402,366	401,130	400,256	398,656	400,499	403,655	407,057
Santa Clara	Y	A	1,685,842	1,690,395	1,673,028	1,667,762	1,668,984	1,682,383	1,700,089	1,723,927	1,755,849	1,784,642
Santa Cruz	N	A	255,834	255,644	253,708	251,559	250,420	248,957	248,758	250,126	252,929	256,218
Shasta	N	S	163,782	166,968	171,141	174,417	176,467	177,537	178,449	179,334	180,515	181,099
Sierra	N	S	3,569	3,506	3,462	3,479	3,394	3,332	3,371	3,312	3,250	3,174
Solano	Y	A	396,974	403,862	407,855	408,397	408,346	406,605	406,181	405,994	406,293	407,234
Sonoma	Y	A	460,411	464,454	463,593	463,715	463,211	461,359	459,783	461,424	466,424	472,102
Stanislaus	N	S	449,702	463,783	477,197	486,512	491,558	498,592	502,989	506,411	507,450	510,385
Sutter	N	A	79,149	79,941	81,767	84,067	85,653	87,670	89,746	91,497	92,127	92,614
Tehama	N	A	56,136	56,474	57,000	57,933	58,784	59,587	60,374	60,764	61,143	61,138
Tuolumne	N	S	54,651	55,162	55,681	56,213	56,185	56,267	56,068	55,681	55,616	55,175
Yolo	N	A	169,884	175,390	180,290	182,762	184,993	185,850	189,082	193,912	196,619	199,407
Yuba	N	A	60,334	61,339	62,399	63,462	64,378	67,029	70,012	71,698	72,865	72,925
Lassen	N	S	33,749	33,503	33,300	33,695	34,102	34,037	34,078	35,005	34,547	34,473
Tulare	N	S	368,628	372,592	378,285	386,399	394,996	403,653	409,641	416,189	422,343	429,668

A = all of county in PG&E territory; S = some of county is in PG&E territory

	1-Jul-00	1-Jul-01	1-Jul-02	1-Jul-03	1-Jul-04	1-Jul-05	1-Jul-06	1-Jul-07	1-Jul-08	1-Jul-09
PG&E territory population:	13,239,208	13,418,163	13,511,329	13,613,460	13,705,006	13,810,778	13,916,250	14,059,064	14,228,915	14,391,915
										rate per yr
										0.93%



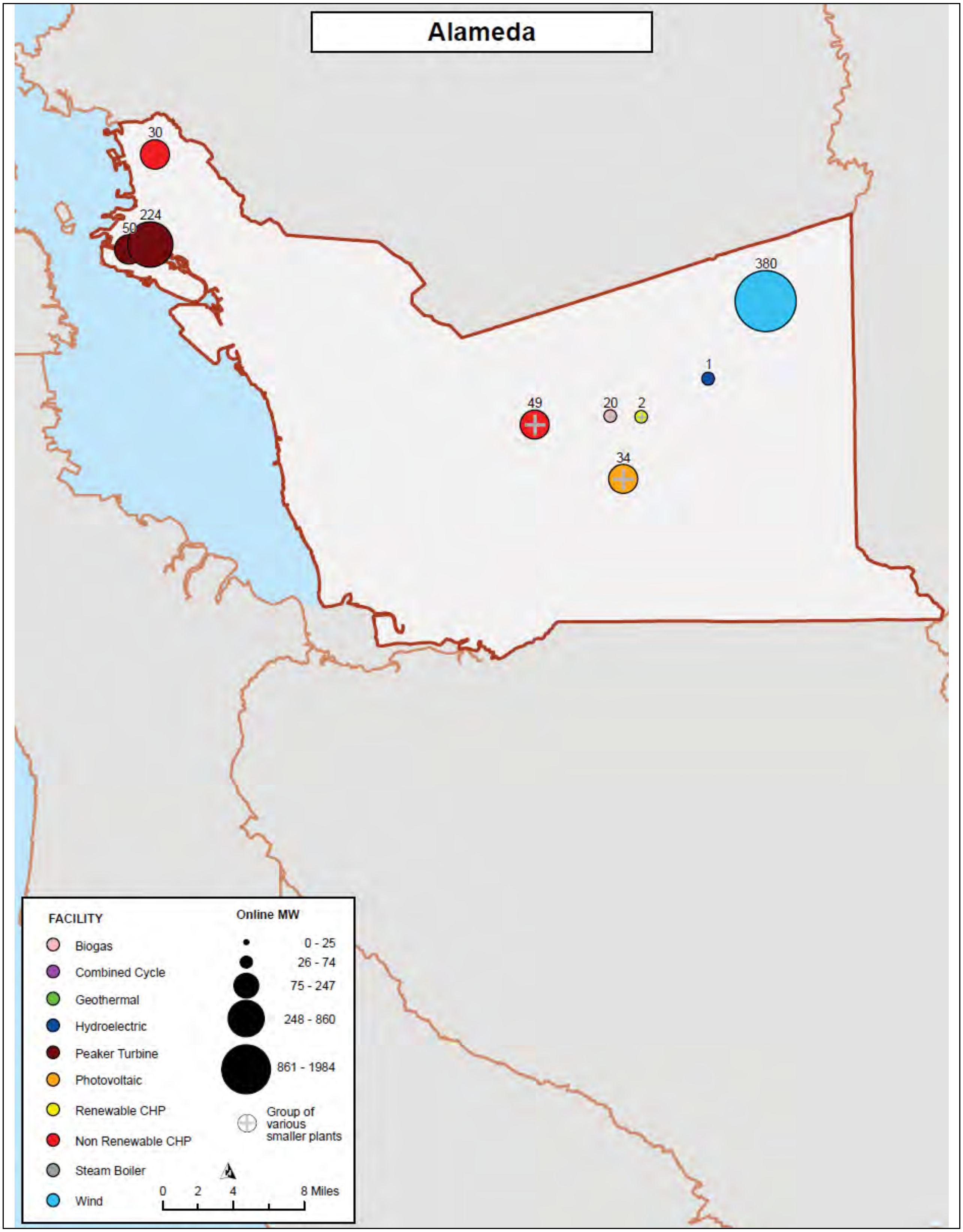
source of data: http://www.census.gov/popest/counties/tables/CO-EST2009-01-06.xls

Appendix B

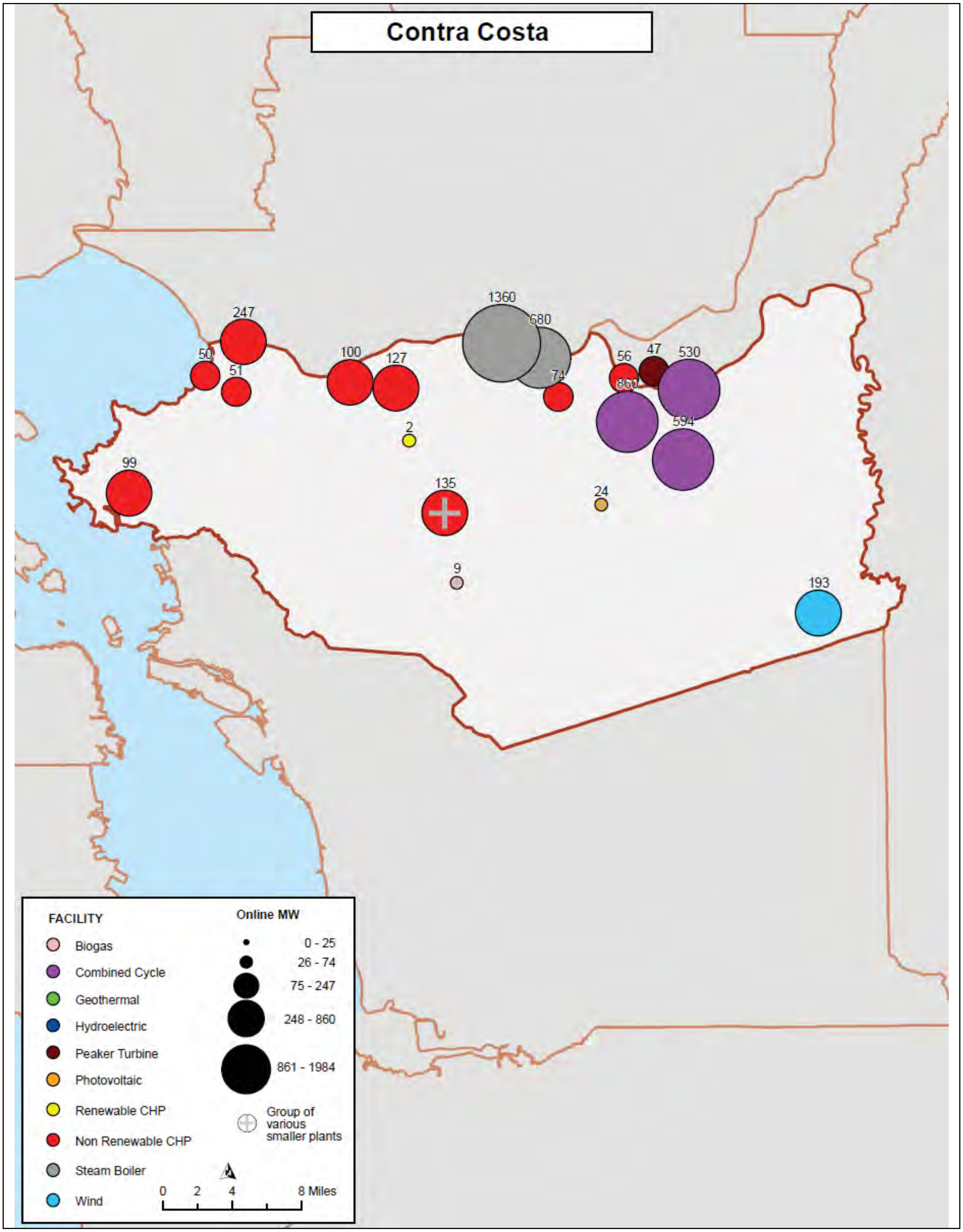
Bay Area Substation Map and County Maps with Generation Sources

Bay Area Substations

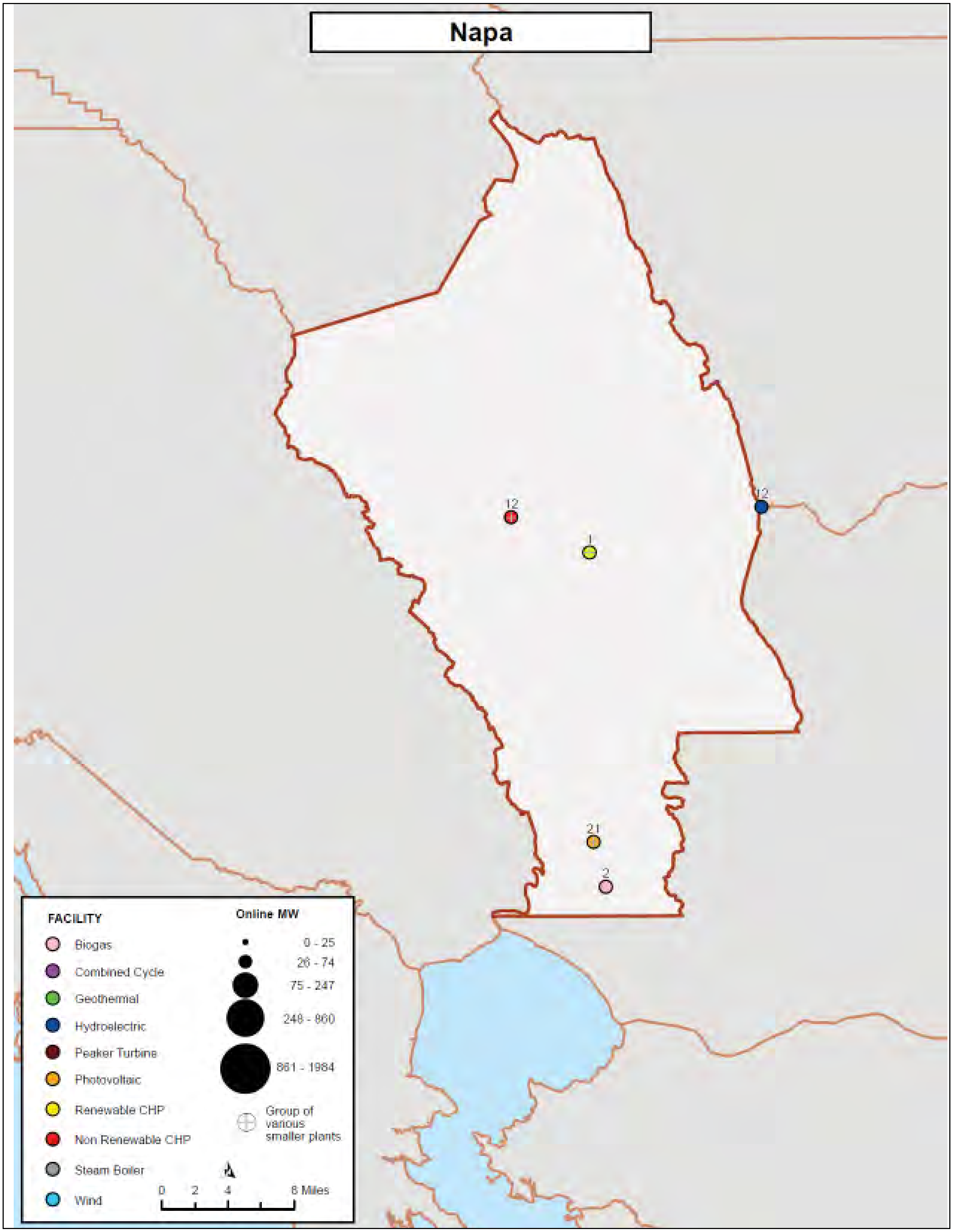
Source: http://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/pvmap/

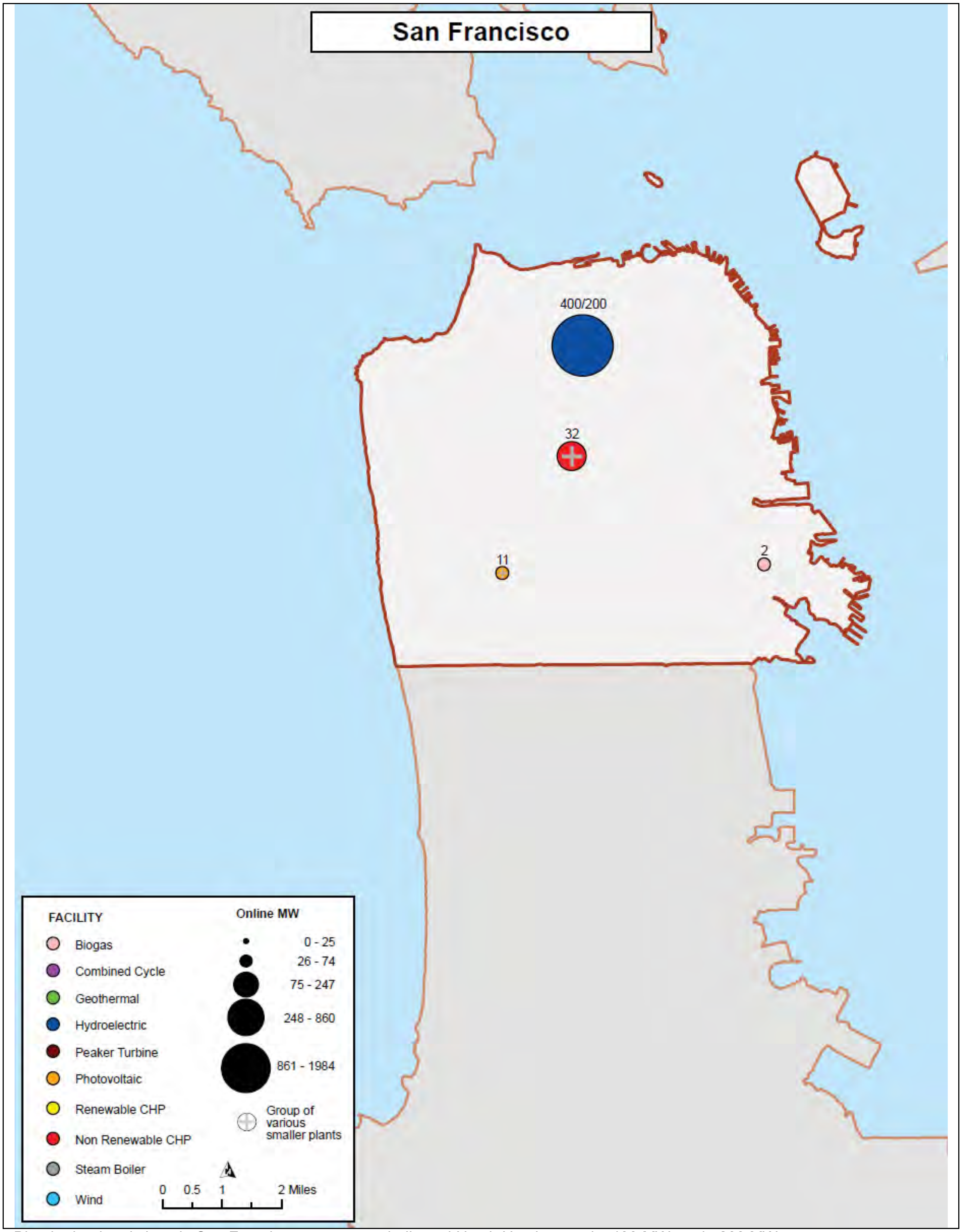


Alameda
30
224
50
380
1
49
20
2
34
FACILITY
Biogas
Combined Cycle
Geothermal
Hydroelectric
Peaker Turbine
Photovoltaic
Renewable CHP
Non Renewable CHP
Steam Boiler
Wind
Online MW
0 - 25
26 - 74
75 - 247
248 - 860
861 - 1984
Group of various smaller plants
0 2 4 8 Miles

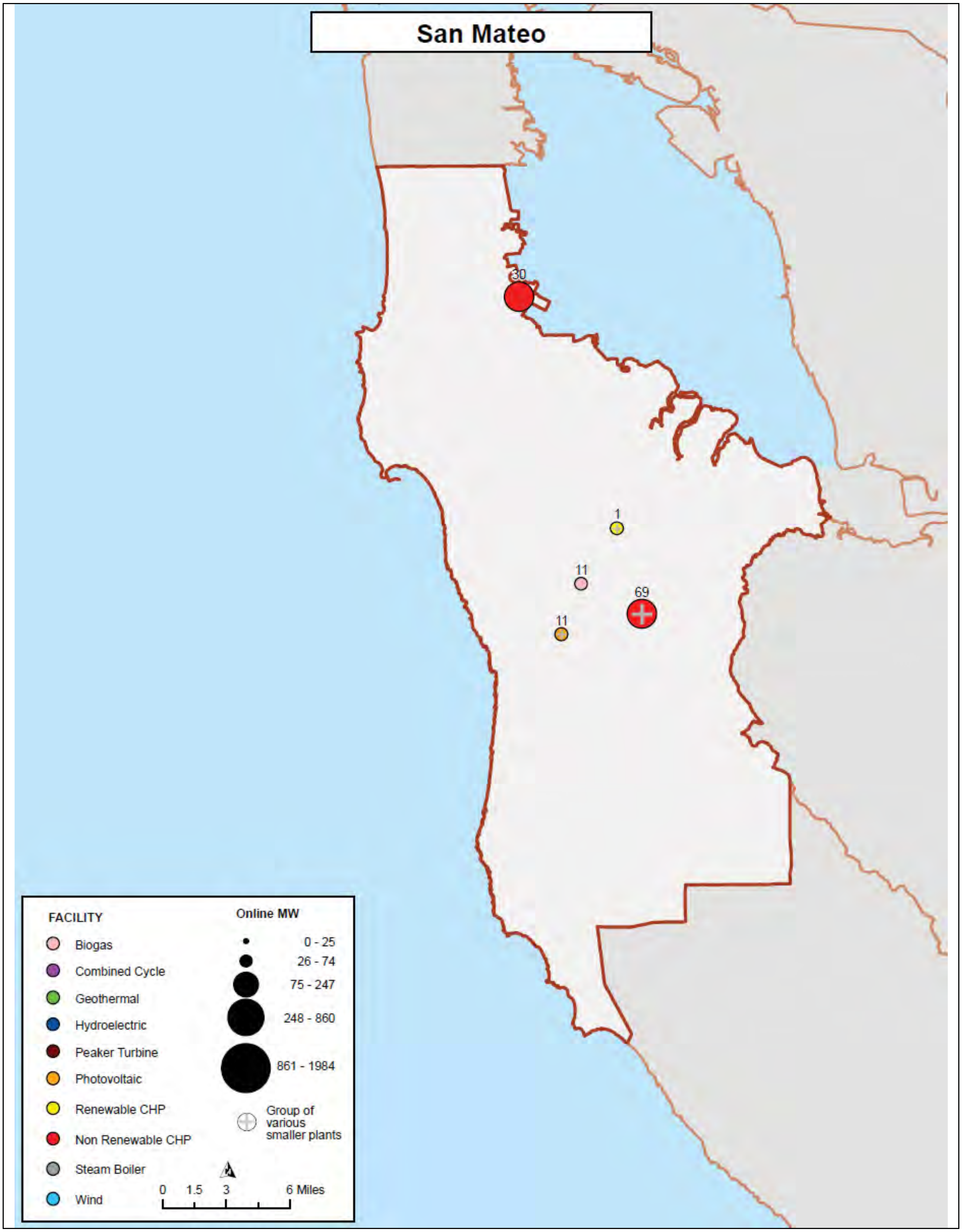

Contra Costa
1360
680
247
50
51
100
127
74
56
47
530
860
594
2
99
135
24
9
193
FACILITY
Biogas
Combined Cycle
Geothermal
Hydroelectric
Peaker Turbine
Photovoltaic
Renewable CHP
Non Renewable CHP
Steam Boiler
Wind
Online MW
0 - 25
26 - 74
75 - 247
248 - 860
861 - 1984
Group of various smaller plants
0 2 4 8 Miles

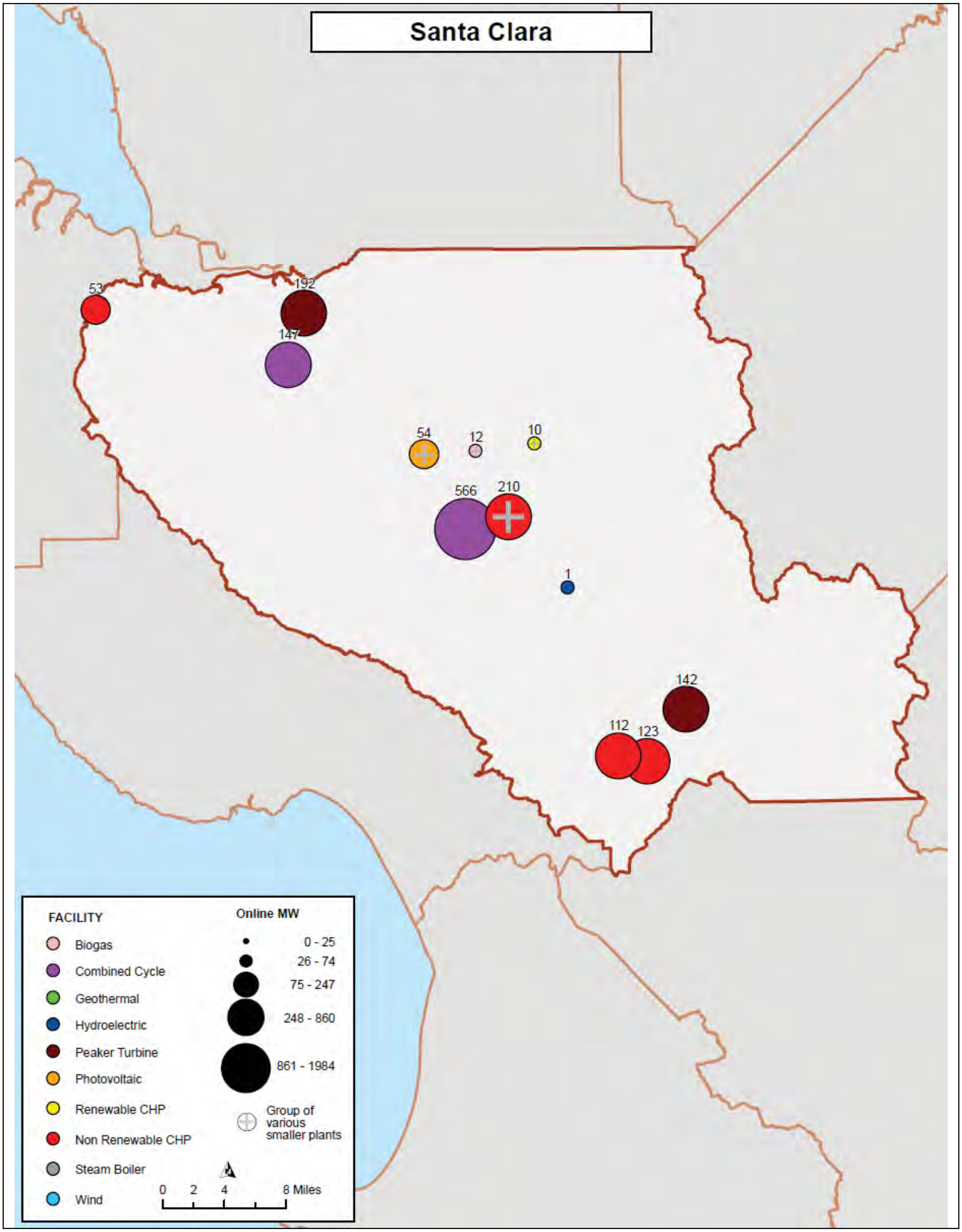
Marin
8
9
FACILITY
Biogas
Combined Cycle
Geothermal
Hydroelectric
Peaker Turbine
Photovoltaic
Renewable CHP
Non Renewable CHP
Steam Boiler
Wind
Online MW
0 - 25
26 - 74
75 - 247
248 - 860
861 - 1984
Group of various smaller plants
0
1.5
3
6 Miles

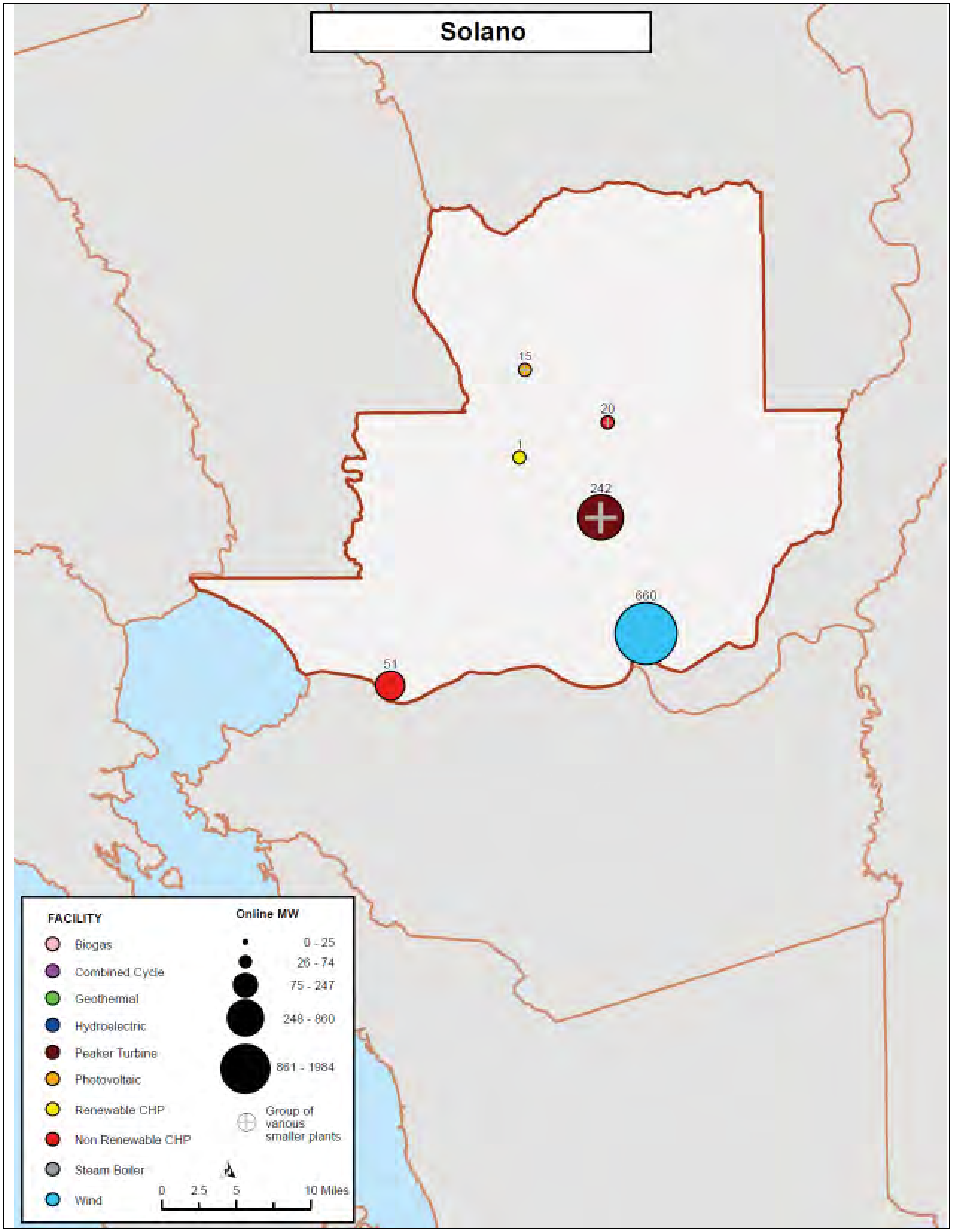

Napa
12
12
1
21
2
FACILITY
Biogas
Combined Cycle
Geothermal
Hydroelectric
Peaker Turbine
Photovoltaic
Renewable CHP
Non Renewable CHP
Steam Boiler
Wind
Online MW
0 - 25
26 - 74
75 - 247
248 - 860
861 - 1984
Group of various smaller plants
0 2 4 8 Miles



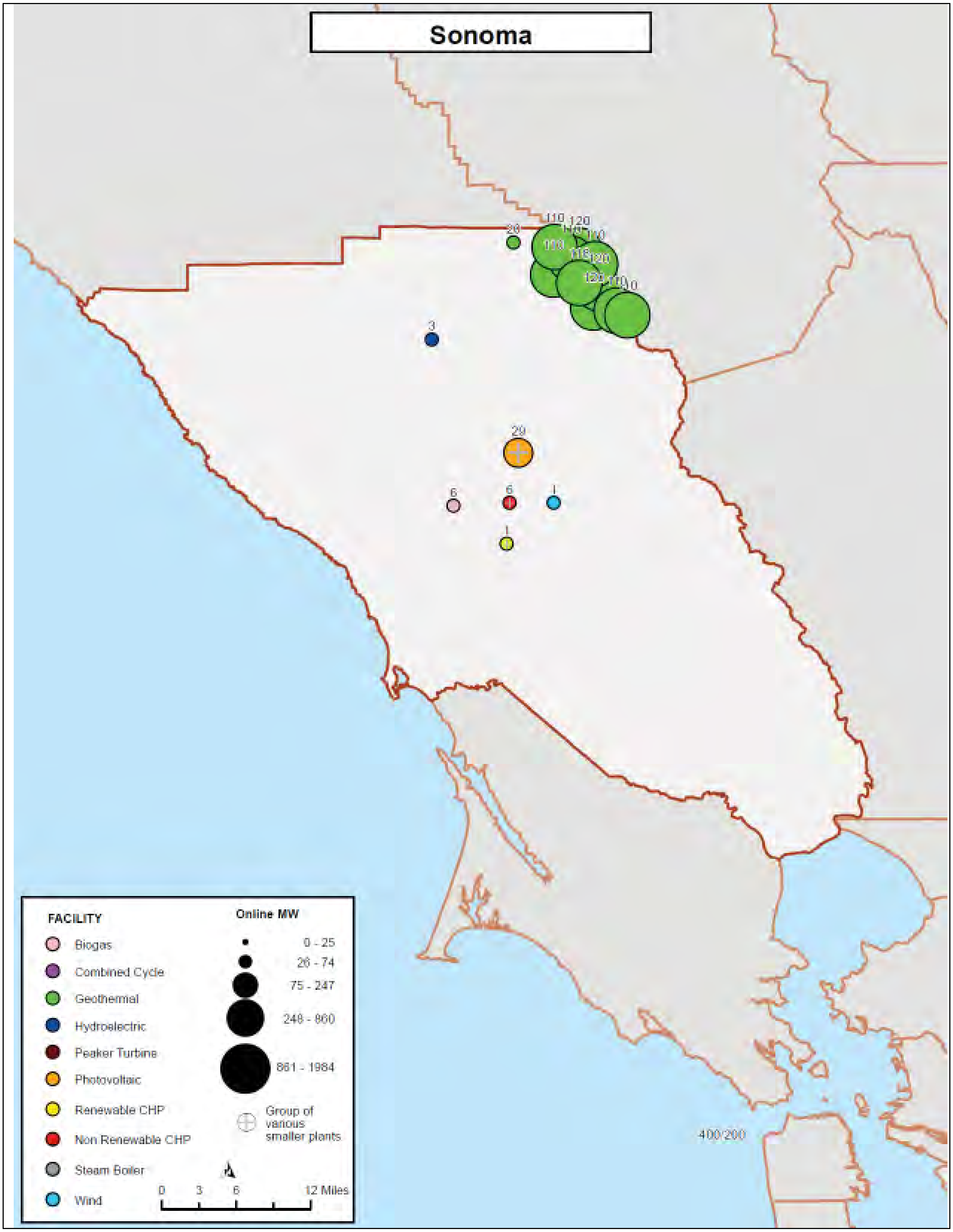
Blue hydroelectric icon in San Francisco represents dedicated Hetch Hetchy supply: 400 MW peak, 200 MW average.


San Mateo
30
1
11
69
11
FACILITY
Biogas
Combined Cycle
Geothermal
Hydroelectric
Peaker Turbine
Photovoltaic
Renewable CHP
Non Renewable CHP
Steam Boiler
Wind
Online MW
0 - 25
26 - 74
75 - 247
248 - 860
861 - 1984
Group of various smaller plants
0 1.5 3 6 Miles


Santa Clara
53
192
147
54
12
10
566
210
1
142
112
123
FACILITY
Biogas
Combined Cycle
Geothermal
Hydroelectric
Peaker Turbine
Photovoltaic
Renewable CHP
Non Renewable CHP
Steam Boiler
Wind
Online MW
0 - 25
26 - 74
75 - 247
248 - 860
861 - 1984
Group of various smaller plants
0 2 4 8 Miles



Solano
15
20
1
242
660
51
FACILITY
Biogas
Combined Cycle
Geothermal
Hydroelectric
Peaker Turbine
Photovoltaic
Renewable CHP
Non Renewable CHP
Steam Boiler
Wind
Online MW
0 - 25
26 - 74
75 - 247
248 - 860
861 - 1984
Group of various smaller plants
0 2.5 5 10 Miles


Sonoma
FACILITY
Biogas
Combined Cycle
Geothermal
Hydroelectric
Peaker Turbine
Photovoltaic
Renewable CHP
Non Renewable CHP
Steam Boiler
Wind
Online MW
0 - 25
26 - 74
75 - 247
248 - 860
861 - 1984
Group of various smaller plants
0 3 6 12 Miles
400/200

Appendix C

Map Showing Location of Bay Area POUs

Source: CEC map, California Electric Utility Service Areas:
[http://www.energy.ca.gov/maps/maps- pdf/UTILITY_SERVICE_AREAS_DETAIL.PDF](http://www.energy.ca.gov/maps/maps-pdf/UTILITY_SERVICE_AREAS_DETAIL.PDF)

Appendix D

Comparison of Bay Area Actual and Potential Solar Irradiance,
2007 Peak Demand Hours

2007 Peak Day/Hour Loads				Oakland Airport Solar Availability at Peak					San Jose Airport Solar Availability at Peak				
2007 peak day	peak hour ending @	CAISO load	PG&E load	cloud cover during actual peak load hour %	global irradiance (GI) during actual peak load hour	closest clear day (0% cloud cover), same hour	closest clear day GI at same hour	% actual GI at peak hour vs clear day GI at peak hour	cloud cover during actual peak load hour %	GI during actual peak load hour	closest clear day (0% cloud cover), same hour	closest clear day GI at same hour	% actual GI at peak hour vs clear day GI at peak hour
6/14/2007	15	40,895	19,778	0	773	6/14/07, 15	773	100	0	773	6/14/07, 15	773	100
7/2/2007	16	41,485	16,935	12.5	608	6/25/07, 16	610	100	12.5	605	6/25/07, 16	583	104
7/3/2007	15	42,748	17,983	12.5	775	6/25/07, 15	779	99	12.5	773	6/27/07, 15	767	101
7/5/2007	17	44,696	21,184	44	408	6/25/07, 17	417	98	44	401	6/21/07, 17	405	99
7/6/2007	15	43,696	19,758	12.5	772	6/25/07, 15	779	99	0	749	7/6/07, 15	749	100
7/31/2007	14	41,834	18,900	12.5	878	7/30/07, 14	879	100	0	866	7/31/07, 14	866	100
8/1/2007	15	41,710	18,475	12.5	693	7/30/07, 15	750	92	0	745	8/1/07, 15	745	100
8/2/2007	16	42,113	18,268	12.5	575	7/30/07, 16	579	99	12.5	566	8/1/07, 16	574	99
8/3/2007	16	42,952	18,901	12.5	572	7/30/07, 16	579	99	0	570	8/3/07, 16	570	100
8/13/2007	16	41,996	16,782	0	538	8/13/07, 16	538	100	0	542	8/13/07, 16	542	100
8/14/2007	16	42,889	17,084	12.5	540	8/13/07, 16	538	100	12.5	538	8/13/07, 16	542	99
8/15/2007	16	43,481	17,218	12.5	537	8/13/07, 16	538	100	12.5	535	8/13/07, 16	542	99
8/16/2007	15	42,981	16,647	0	709	8/16/07, 15	709	100	12.5	701	8/15/07, 15	696	101
8/17/2007	15	42,439	16,344	0	706	8/17/07, 15	706	100	0	693	8/17/07, 15	693	100
8/20/2007	16	44,294	18,411	0	501	8/20/07, 16	501	100	12.5	517	8/19/07, 16	521	99
8/21/2007	16	44,707	19,380	12.5	516	8/20/07, 16	501	103	0	502	8/21/07, 16	502	100
8/22/2007	15	43,478	19,807	0	688	8/22/07, 15	688	100	0	680	8/22/07, 15	680	100
8/23/2007	14	42,195	19,100	0	770	8/23/07, 14	770	100	12.5	815	8/22/07, 14	797	102
8/24/2007	15	41,325	18,290	12.5	679	8/23/07, 15	675	101	0	667	8/24/07, 15	667	100
8/27/2007	15	42,245	17,715	0	624	8/27/07, 15	624	100	0	649	8/27/07, 15	649	100
8/28/2007	16	46,033	19,651	12.5	453	8/27/07, 16	458	99	12.5	484	8/27/07, 16	476	102
8/29/2007	16	48,553	21,230	12.5	471	8/27/07, 16	458	103	12.5	473	8/27/07, 16	476	99
8/30/2007	15	48,074	20,489	12.5	656	8/28/07, 15	589	111	12.5	633	8/28/07, 15	644	98
8/31/2007	16	48,823	20,553	12.5	472	8/27/07, 16	458	103	12.5	466	8/27/07, 16	476	98
9/1/2007	15	44,758	18,443	0	648	9/1/07, 15	648	100	12.5	648	8/28/07, 15	644	101
9/2/2007	15	43,940	17,626	0	649	9/2/07, 15	649	100	0	649	9/2/07, 15	649	100
9/3/2007	14	44,674	17,588	0	785	9/3/07, 14	785	100	0	787	9/3/07, 14	787	100
9/4/2007	14	44,616	16,731	12.5	781	9/3/07, 14	785	99	12.5	783	9/3/07, 14	797	98
9/5/2007	14	41,114	17,260	0	691	9/3/07, 14	691	100	0	778	9/5/07, 14	778	100

Global Irradiance: Solar radiation incident outside the Earth's atmosphere is called extraterrestrial radiation. On average the extraterrestrial irradiance is 1,367 Watts/square meter (W/m^2). Near noon on a day without clouds, about 25% of the solar radiation is scattered and absorbed as it passes through the atmosphere. Therefore about 1,000 W/m^2 of the incident solar radiation reaches the Earth's surface without being significantly scattered. This radiation, coming from the direction of the sun, is called direct normal irradiance. The scattered radiation reaching the earth's surface is called diffuse radiation. The total solar radiation on a horizontal surface is called global irradiance and is the sum of incident diffuse radiation plus the direct normal irradiance projected onto the horizontal surface.
Reference: http://solardat.uoregon.edu/SolarRadiationBasics.html

2007 global irradiance hourly data for Oakland Airport and San Jose Airport was obtained from the Solar Anywhere online database: https://www.solaranywhere.com/Public/About.aspx

SolarAnywhere generates global irradiance estimates using NOAA GOES visible satellite images. The global irradiance hourly data is provided for 5 mile x 7 mile blocks (~100 square km), or "tiles."
The hourly satellite images are processed using the algorithms developed and maintained by Dr. Richard Perez at the University at Albany (SUNY). The algorithm extracts cloud indices from that satellite's visible channel using a self-calibrating feedback process that is capable of adjusting for ground surfaces. The cloud indices are used to adjust the irradiance transfer models and calculate the expected hour-by-hour irradiance for each 100 square km. tile.

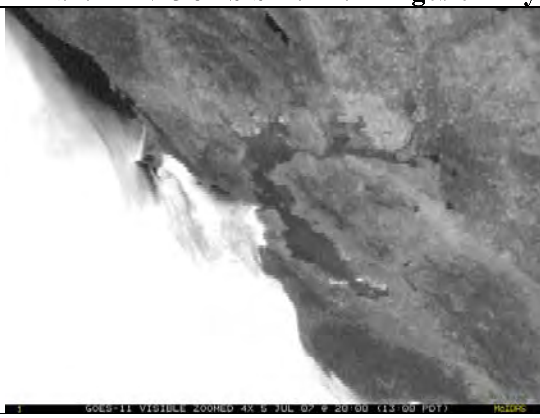
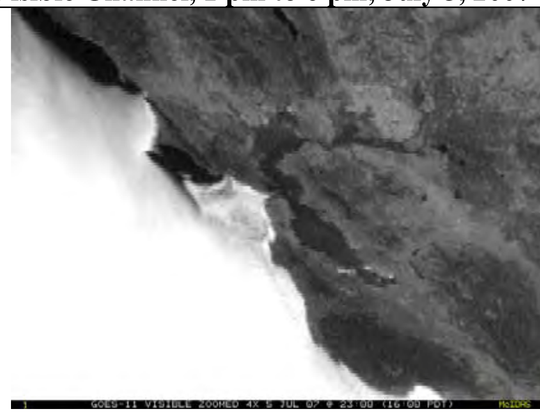
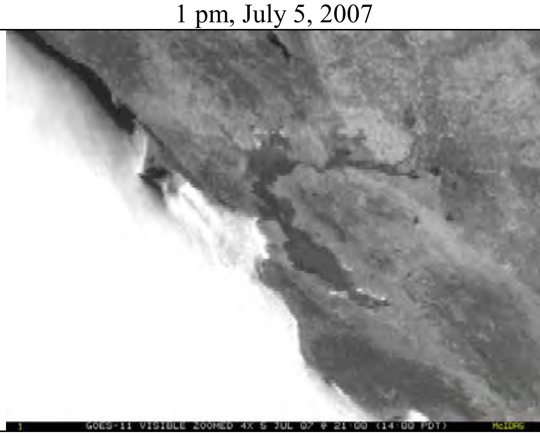
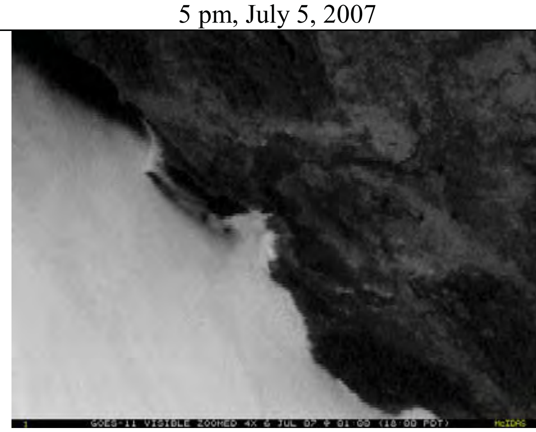
2007 cloud cover hourly data for Oakland Airport and San Jose Airport is U.S. National Climate Data Center (NCDC) data purchased from Weather Warehouse. Code used for NCDC cloud cover values:
0: CLEAR - No clouds. 1: FEW - 2/8 or less coverage (not including zero). 2: SCATTERED - 3/8-4/8 coverage. 3: BROKEN - 5/8-7/8 coverage. 4: OVERCAST - 8/8 coverage.
To convert this cloud cover code to % cloud cover:
FEW: 2/8 or less, so 1/8 on average: 12.5% (Weather Warehouse reports worst case of 25%) BROKEN: 6/8: 75%
SCATTERED: 3.5/8 on average: 44% (Weather Warehouse reports worst case of 50%) OVERCAST: 100%

During one peak hour, 4-5 pm on July 5, 2007, both Oakland and San Jose Airports registered scattered clouds when the global irradiance projection for both 100 square km. tiles where these airports are located was near 100 percent. The presence of scattered clouds in the vicinity of these two airports, with generally clear skies in the remainder of the two separate 100 square km. tiles where these airports are located, is one potential explanation for this discrepancy between irradiance and cloud cover. In all other cases, cloud cover was either zero or near zero.

Resolution of July 5, 2007, 4 pm to 5 pm data discrepancy: scattered clouds reported at Oakland and San Jose Airports while 98 percent GI modeled for same sites at same hour

On July 5, 2007, the PG&E service territory peak was 21,184 MW from 4 to 5 pm. Both Oakland Airport and San Jose Airport weather stations registered scattered cloud cover during this hour. However, with the exception of some scattered clouds at a few points around San Francisco Bay and a cloud bank along the Pacific shoreline, the skies in the Bay Area were clear on the afternoon of July 5, 2007. The degree of cloud cover in the Bay Area from 1 pm to 6 pm on July 5, 2007 is shown in the sequence of GOES satellite images in Table H-1.

Table H-1. GOES Satellite Images of Bay Area, Visible Channel, 1 pm to 6 pm, July 5, 2007

	
1 pm, July 5, 2007	4 pm, July 5, 2007
	
2 pm, July 5, 2007	5 pm, July 5, 2007
	
3 pm, July 5, 2007	6 pm, July 5, 2007

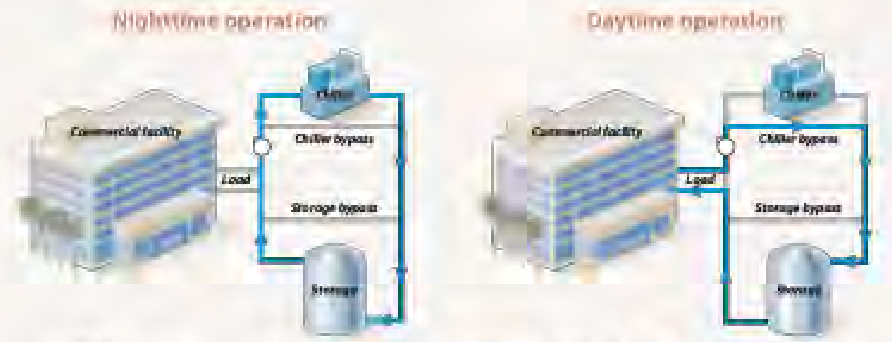
Source of GOES satellite images: Axel Graumann, meteorologist, Satellite Services Group, Data Access Branch, NOAA National Climatic Data Center, tel: 828-271-4850, ext. 3183. Images provided on April 1, 2011 and April 5, 2011 by e-mail.

Appendix E

Graphic of Peak Cooling Demand Reduction Achieved by Thermal Storage Air Conditioning Systems

Thermal Energy Storage

Thermal energy storage (TES) systems shift energy usage to a later period to take advantage of cheaper time-based utility rates and/or to reduce overall energy demand. In California, the primary use of thermal energy storage is for cool storage since summer air conditioning is the dominant electric load. Cooling storage mediums of choice are water, ice, and eutectic salts.



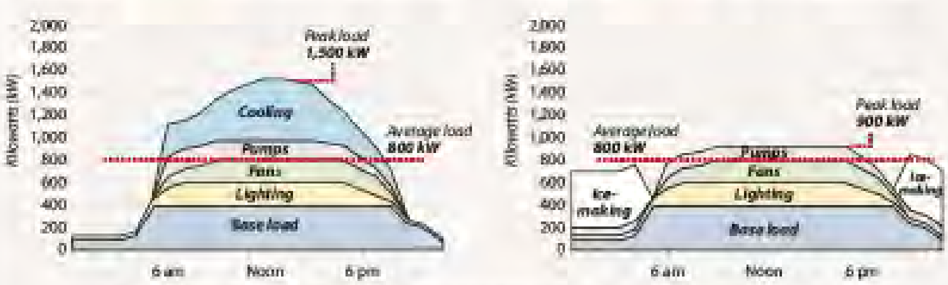
TES systems produce chilled water (or ice) during the night and store for use during the day. This allows central plant equipment to operate at night when energy is readily available, cheaper, and the chiller equipment can run more efficiently. By doing so, buildings can reduce peak demand on the electrical grid and decrease their electrical usage and demand costs.

Benefits of Thermal Energy Storage:

1. Reduce peak demand
2. Decreased electric usage and demand costs.
3. Increased central plant redundancy
4. Reduced emissions from inefficient peaker plants
5. Reduced chiller plant size and corresponding infrastructure

DAILY ELECTRICITY LOAD

Building without Thermal Energy Storage **Building with Thermal Energy Storage**



These two graphs show electrical load profiles for similar buildings with and without Thermal Energy Storage. The graph on the left represents a building without TES. The graph on the right represents a building with TES, where all the ice making is done at night, during off-peak hours.

© San Diego Regional Energy Office

Graphic by PAUL HORN

Appendix F

Description of Natural Gas Savings from 60 kW CHP Project in Richmond, California

Cogeneration at Work

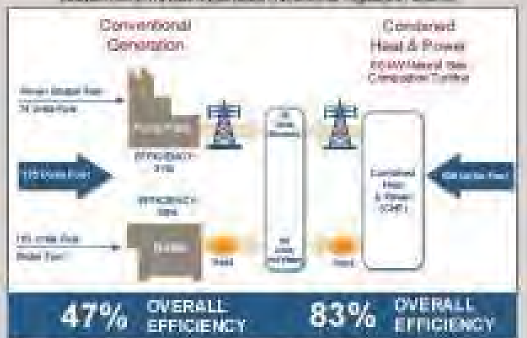
EPA Region 9 Laboratory
Richmond, California

The U.S. Environmental Protection Agency (EPA) is leading by example in reducing the energy demand of its Region 9 Laboratory by approximately 21 percent. In 2006, EPA completed three major building upgrades:

- A natural gas-fired cogeneration unit to produce electricity and hot water on site.
- Two small, efficient boilers to replace an oversized one.
- A series of control upgrades for its heating, ventilation, and air conditioning (HVAC) system.

EPA expects these new systems to pay for themselves through annual savings of more than $90,000 per year and a one-time rebate from the local California utility of $40,000.

Cogeneration Efficiency Advantages for EPA's Region 9 Laboratory



[illegible]

Energy and Cost Savings

[illegible]

Projected Savings At-a-Glance

Energy Savings (MMBtu/year)	Cost Savings ($/year)
Natural Gas	
1,474.6 MMBtu*	$24,460**
Electricity	
1,678.7 MMBtu***	$65,807
Total Annual Savings	
3153.3 MMBtu	$90,268

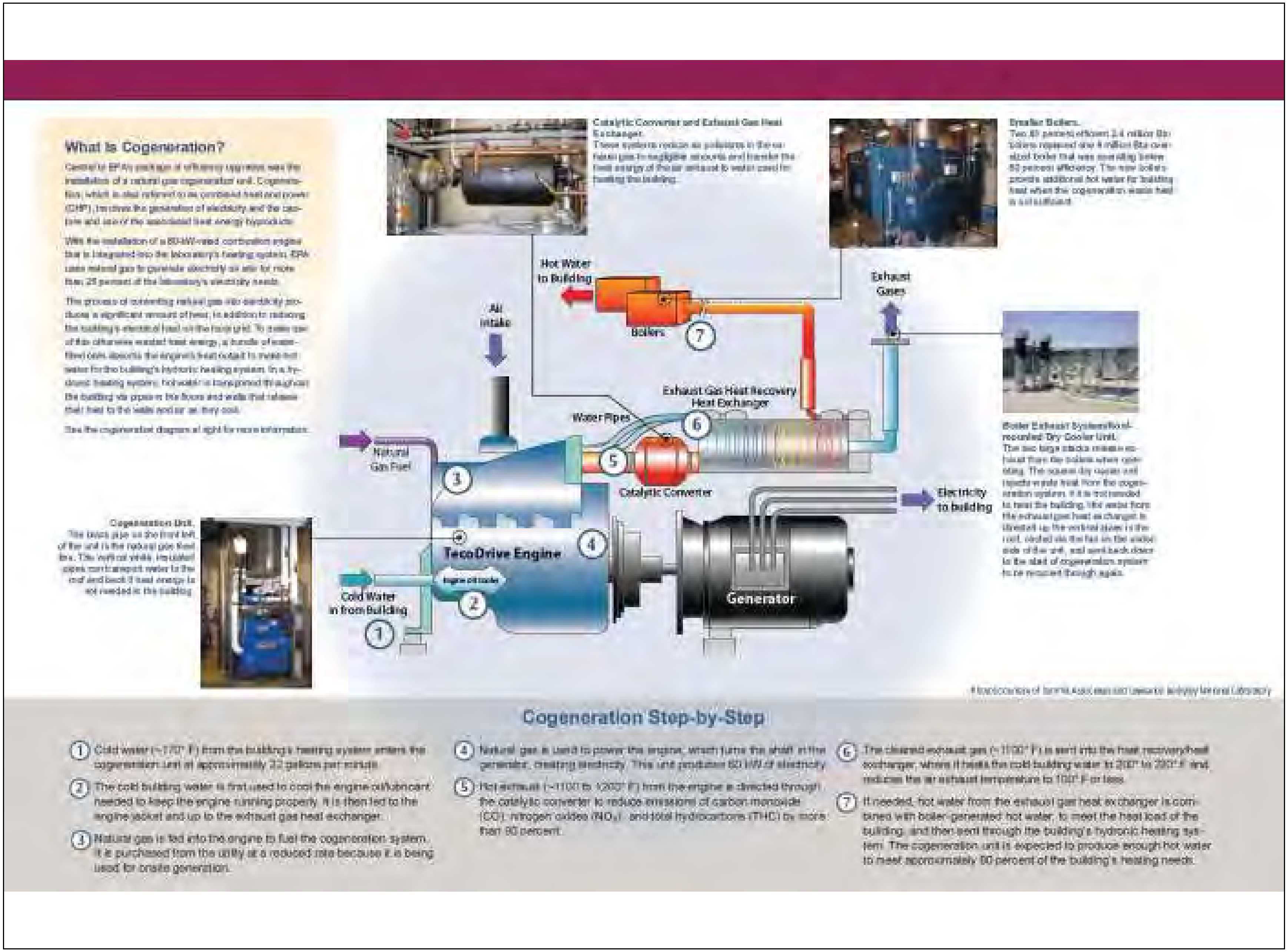
[illegible]

[illegible]

Facility Statistics

Facility Type:	Laboratory
Construction:	Mechanical upgrades
Location:	Richmond, California
Total Facility Area:	44,950 gross square feet (GSF)
Estimated Personnel:	44 persons
Fiscal Year (FY) 2006 Energy Use:	14,787,109,635 British thermal units (Btus) per year 328,966 Btus per GSF per year
Projected Energy Use:	11,687,150,750 Btus per year 260,003 Btus per GSF per year

[illegible]


What is Cogeneration?
Hot Water
to Building
Air
intake
Boilers
Exhaust
Gases
Exhaust Gas Heat Recovery
Heat Exchanger
Water Pipes
Natural
Gas Fuel
Catalytic Converter
Electricity
to building
TecoDrive Engine
Cold Water
in from Building
Generator
Cogeneration Step-by-Step
1 Cold water (~170° F) from the building's heating system enters the cogeneration unit at approximately 22 gallons per minute.
2 The cold building water is first used to cool the engine oil/lubricant needed to keep the engine running properly. It is then fed to the engine jacket and up to the exhaust gas heat exchanger.
3 Natural gas is fed into the engine to fuel the cogeneration system. It is purchased from the utility at a reduced rate because it is being used for onsite generation.
4 Natural gas is used to power the engine, which turns the shaft in the generator, creating electricity. This unit produces 60 kW of electricity.
5 Hot exhaust (~1100 to 1200° F) from the engine is directed through the catalytic converter to reduce emissions of carbon monoxide (CO), nitrogen oxides (NOx), and total hydrocarbons (THC) by more than 90 percent.
6 The cleaned exhaust gas (~1100° F) is sent into the heat recovery/heat exchanger, where it heats the cold building water to 200° to 230° F and reduces the air exhaust temperature to 100° F or less.
7 If needed, hot water from the exhaust gas heat exchanger is combined with boiler-generated hot water, to meet the heat load of the building, and then sent through the building's hydronic heating system. The cogeneration unit is expected to produce enough hot water to meet approximately 90 percent of the building's heating needs.

Appendix G

Calculation of Net Capital Cost of Commercial PV System after Federal Tax Benefits

The 100 kW_{dc} system example provided in Table G-1 demonstrates the financial impact of the incentive payment and tax credits on the net cost of commercial PV system. The 100 kW_{dc} system used in the example is presumed to be a system installed on a commercial rooftop and owned by a commercial business.

Table G-1. Effect of Federal Tax Benefits o n Net Cost of 100 kW PV System[1]

Cost or (Credit) $	Cost Element
400,000	gross capital cost of 100 kW_{dc} PV system @ approximately $4 per installed W_{dc}
(120,000)	30 percent federal tax credit on gross capital cost
(112,000)	depreciation on gross cost less tax credit ($280,000 × tax rate), assume tax rate is 40 percent
168,000	net cost of PV system

The annual loan payment would be $16,000 per year, assuming the net capital cost of $168,000 is amortized at 7 percent interest over 20 years.[2] Operations and maintenance cost is estimated at $2,000 per year.[3] Therefore, total annual expenses would be $16,000/yr + $2,000/yr = $18,000/yr.

This system would be expected to generate approximately 1,500 kWh per year kW_{dc} installed.[4] Total electricity output would be 1,500 kWh/kW_{dc} per year × 100 kW_{dc} = 150,000 kWh per year. Dividing the annual cost of $18,000 by the annual electricity production of 150,000 kWh gives a break-even electricity generation cost of $0.12/kWh.

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[1] June 19, 2007 and September 4, 2007 e-mails from J. Supp, CSI program manager, Center for Sustainable Energy California, San Diego, to B. Powers. The example provided by Mr. Supp was for a 12 kW_{dc} commercial PV system receiving a CSI incentive payment and federal tax benefits. In Table H-1, the CSI incentive has been eliminated and the size of the PV system has been increased from 12 kW_{dc} to 100 kW_{dc}.

[2] The capital recovery factor for a 20-year, 7 percent loan is 0.0944. Therefore, the annual payment on capital expense would be: 0.0944 x $168,000 = $15,859/yr.

[3] Operations and maintenance (O&M) cost is assumed to be $20/kW-yr. Therefore, O&M cost = $20/kW-yr × 100 kW = $2,000/yr.

[4] NREL PV Watts V.1 Calculator estimates 6,013 kWh per year of electricity production from a 4 kW_{dc} fixed PV array in San Francisco at a dc-to-ac conversion efficiency of 0.80: http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/US/California/San_Francisco.html. Therefore the output of the system per kW_{dc} of capacity = 6,013 kWh/yr ÷ 4 kW_{dc} = 1,504 kWh per year.

Appendix H

ZBB Energy Grid Interactive Platform
[community microgrid operation]

Grid Interactive Platform

When ZBB's EnerSystem™ power and energy control system is connected to a stable grid, it can be used as a bi-directional, hybrid conversion platform, integrating multiple renewable and/or conventional power sources with energy storage. It provides for steady state output, emergency power supply and/or arbitrage pricing schemes to and from the utility supply.

Take Control of Your Power

The utility companies don't have to be in charge of the cost and quality of your energy supply. You can take control of your power needs and have energy – even green energy, on your own terms:

- Manage the output of your resources and dictate the quality of your own energy supply
- Be free from total dependence on the grid
- You can have reliable, constant power, even if wind or solar are your main energy source
- Sell your excess generated supply and even stored energy back to the grid when its optimal for you to do so – not just for the utility company

ZBB's EnerSystem supports any combination of generating sources, including the grid as a two-way input.

You need a platform configuration that supports your electrical demands while optimizing all of the interconnected resources available to you – beyond your singular connection to the grid.

The Answer is ZBB

ZBB's EnerSystem can be configured to create a hybrid power conversion system for grid-interactive applications anywhere in the world. When combined with ZBB's EnerStore™ Zinc-bromide flow batteries or other energy storage devices, the platform creates an expandable system that independently optimizes the supply of each generating source. This provides a grid-synching architecture that directs power flows to and from the grid based on demand response, load management and shifts supply by time of day for peaking needs. It can even be used as an emergency power system independently of the grid during outages.

ZBB's EnerSystem integrated energy management platform:

- Provides a continuous supply of energy and optimizes all of the interconnected resources
- Eliminates the variable output of renewable energy sources
- Easily integrates one or multiple energy generation sources now and in the future
- Provides storage devices for both inexpensive and premium application needs
- Uses off-grid inverters or inverter sets that form their own highly reliable micro-grid

ZBB's EnerSystem is an integrated, factory built and tested energy management system that operates 24-hours a day, 365 days of the year, regardless of available power.

ZBB energy corporation

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ZBB Energy

Grid Interactive Platform

Be In Control

Based on performance, cost, or availability of resources – you can manage your power needs with:

- Direct grid connection with bi-directional power flows
- Independent control over active/reactive power dispatch to improve power quality
- Integrated renewable, advanced and conventional generation sources
- Hybrid configurations of energy storage (flow batteries and other devices) in parallel operation
- Smart-Grid 'demand response/dispatch' assets as an additional revenue source where available
- Renewable generation ramp control/voltage smoothing/frequency regulation
- Power quality management with included power electronics in place of other external devices

Optimize Your Resources

Power quality and reliability is critical, and with ZBB's EnerSystem you don't have to be subject to the grid's continually increasing costs and intermittent supply, or be constrained to meet the rising demands of your facilities.

ZBB's EnerSection™ is scalable, modular, flexible and configurable. It will support you with an energy storage system that allows many diverse energy sources to run at their discrete optimized levels – maximizing total power availability. ZBB's interactive energy format features:

- An open and simplistic design
- A complete installed solution cost
- The ability to manage complex electrical site requirements
- Accommodates multiple AC and DC load and generation types
- Easy installation, configuration and training
- Fewer parts (SKUs) for more efficient inventories
- Low maintenance requirements, higher availability and improved efficiency
- Superior electrical energy performance and reliability
- Low, ongoing costs

Capture Multiple Value Streams

ZBB's EnerSystem manages the onsite supply and demand in a bi-directional flow to and from the grid which allows you to capture multiple value streams, using energy storage as a "shock absorber" between the changes in outputs, demands and cost of supply. It also creates a reserve supply of energy to use during peak times and in emergency outages so you can:

- Reduce demand charge and peak pricing costs of power supply from the grid
- Sell power at peak prices or be paid to use storage on demand from the grid
- Integrate multiple onsite power sources with dedicated loads
- Smarter use of all onsite assets into an emergency power system

Whatever Your Energy Source or Connection

ZBB optimizes energy availability with its integrated management platform and intelligent storage – so you can take control of your power and energy needs on your own terms.

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Appendix I

Description of SolarWall™ Air Heating at NREL Research Support Facility

Government

NREL - Research Support Facility

NREL's LEED Platinum Plus Research Support Facility showcasing innovative green technologies such as the SolarWall® solar air heating system (above, the two south facing charcoal SolarWall® systems)

Background

When NREL (National Renewable Energy Laboratory; a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy) was tasked with building their next sustainable green building, a new Research Support Facility (RSF), it was decided the 222,000 ft² office building would be a showcase for energy efficiency and renewable energy technologies.

NREL's RSF is the largest Net Zero building in the US with 800+ staff and aiming for LEED Platinum Plus rating from the USGBC. The RSF was designed to use 50% less energy than a standard office building, and incorporates a number of green innovations such as day lighting, natural ventilation, building integrated PV and a SolarWall solar air heating system.

Solution

The SolarWall® system, with zero maintenance and proven performance metrics was easily integrated into the buildings south facing façade. The panels were mounted horizontally and (with very little effort) incorporated around numerous windows. The two charcoal colored SolarWall® systems span over 8,640ft² and pre-heat the fresh ventilation air using the sun, reducing heating costs and GHG emissions.

Results

The SolarWall systems at the RSF is projected to deliver over 238 Mwh (856 GJ) of end use annual energy. The annual GHG emission reductions is over 53 tones of CO_2 per year.

Aerial view of NREL's Research Support Facility, the two SolarWall systems are visible in the bottom left of the photo

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