Developing Cost-Effective Solar Resources with Electricity System Benefits

IN SUPPORT OF THE
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STAFF PAPER

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Abstract

Under California's Renewable Portfolio Standard (RPS) and the Energy Action Plan, electricity suppliers must provide up to twenty percent of electricity purchases from renewable resources by 2010. This draft white paper presents a method for evaluating the ability to use California's solar resources as cost-effective contributions to the RPS goals, and assessing the impacts of those contributions on the state's electricity system. Cost and performance trends for concentrating solar power and flat plate photovoltaic technologies are used in a revenue requirement model to generate estimates of levelized costs of electricity generation (LCOE) for the technologies going out to 2017. The resulting LCOE estimates are compared against Market Price Referent (MPR) values and forecasted combined cycle electricity costs to assess the cost-competitiveness of the solar technologies in a 2010 and 2017 timeframe. Power flow analyses are used concurrently to identify locations in the state's electricity system that may face capacity or congestion problems going out to 2017. Geographical Information System (GIS) tools are then used to intersect cost-competitive solar resources with grid system "hot spots." Lastly, combined GIS and power flow analyses are used to evaluate the impacts of developing solar resources that could help meet RPS goals on the state's electricity system. Results of the evaluations are presented for concentrating solar power and flat plate photovoltaic technologies for the 2010 and 2017 timeframes.

Keywords

Solar, renewables portfolio standard (RPS), strategic value analysis (SVA), concentrating solar power (CSP), photovoltaics (PV).

Purpose and Introduction

California has a tremendous supply of renewable resources that can be harnessed to provide clean and naturally replenishing electricity supplies for the state. Currently, renewable resources provide approximately eleven percent of the state's electricity mix.[1]

California's Renewable Portfolio Standard (RPS) established in 2002 by Senate Bill 1078 (SB1078, Sher, Chapter 516, Statutes of 2002) requires electricity providers to procure at least one percent of their electricity supplies from renewable resources to achieve a twenty percent renewable mix by 2017. More recently, the California Energy Commission, the California Public Utilities Commission and the California Power Authority approved the Energy Action Plan (EAP), accelerating the twenty-percent target date to 2010.[2]

An earlier staff paper, California's Solar Resources[3] provided estimates of the "gross" and "technical" potential solar resources available in California. This draft staff paper provides estimates of the quantities and locations of solar resources that could be economically feasible for use in meeting RPS and EAP targets. In addition, this paper provides an assessment of the impacts on the reliability of California's electricity from developing such solar resources. Lastly, this staff paper introduces an evaluation tool, a Strategic Value Analysis that may be helpful to utilities and renewable energy project developers in implementing a "least-cost, best-fit" approach to the RPS. The tool enables project developers and utilities to use a common and transparent method to identify locations in the transmission system that face congestion or capacity problems, the quantities and locations of renewables close to the identified electricity system "hot spots" and the cost-effectiveness and ability of those renewables to help relieve electricity system problems.

Scope and Approach

Solar technologies that convert sunlight to electricity generally fall into two broad categories: concentrating solar power (CSP) systems and non-concentrating systems; primarily flat plate photovoltaic (PV) systems. This paper focuses on CSP and PV systems.

A Strategic Value Analysis (SVA) is the approach used to identify the quantities and locations of solar resources that are economic to develop over the next twelve years, and to assess the impacts that development of these solar resources may have on California's electricity system. The SVA is conducted in four steps. First, performance and cost projections make a "first-cut" economic feasibility assessment of developing solar resources between now and 2017. Second, power flow analyses identify locations in California's electricity system that may face capacity or congestion problems (termed "hot spots") and quantify the magnitude of those problems. Third, solar resources located close to these "hot spots" are identified with the aid of a geographical information system (GIS). This information enables staff to make a "second-cut" assessment of economic feasibility. As a fourth step, the data from the GIS and power flow analysis tools are combined to help assess the impacts of using "economic" solar power on California's electricity system. A more comprehensive description of the SVA approach can be found in the draft white paper entitled "Strategic Value Analysis for Integrating Renewable Technologies in Meeting Target Renewable Penetration."[4]

Concentrating Solar Power

Performance and Cost Trends

Concentrating solar power (CSP) plants typically use one of three primary technologies: parabolic troughs, power towers, or parabolic dish/heat engines (usually Stirling engines). While other CSP technologies are under development, there is limited information on their costs and performance and will not be covered in this paper.

Several types of thermal power systems are used with these solar technologies, depending on size and application. Power tower and parabolic trough solar systems typically produce steam to drive conventional steam Rankine power cycles in the multi-megawatt size range. They are operated as either stand-alone systems or in the bottoming cycle of a combined gas turbine-steam turbine plant. Trough systems are also used to produce high temperature hot water to drive smaller (i.e., in the kilowatt to few megawatt size range) organic Rankine cycle units. Parabolic dish concentrators, on the other hand, provide high temperature thermal energy to drive small kW-scale engines located in the focal point of the dish. Development efforts are currently focused on Stirling engines, though air Brayton cycle engines are also of development interest.

Parabolic Trough Systems

Parabolic trough systems use single-axis tracking[5] parabolic trough arrays to collect solar energy. The solar system is essentially a steam producer, using the collector field, high temperature oil heat transport system and an oil-to-water/steam heat exchanger set to generate superheated steam. The steam is then used in a conventional steam turbine power process to generate electricity.

Worldwide parabolic trough capacity is limited to less than 360 megawatts.[7] Nine trough systems termed the Solar Energy Generating Station (SEGS) facilities were built in the 1980's in the high desert of Southern California by the LUZ Corporation. The SEGS facilities currently represent 354 MW of generating capacity. Sized between 14 and 80 megawatts (MW), these systems are capable of using up to 25 percent of their rated capacity with natural gas to provide dispatchable power when solar energy is not available. With over 16 years of operating experience, parabolic trough technology is proven.

After development of the SEGS facilities, there was a hiatus in construction of new trough plants for a number of reasons. Research and development activities also stopped. In 2000, the National Research Council recommended to the Department of Energy that it "should limit or halt its R&D on power-tower and power-trough technologies because further refinements to these concepts will not further their deployment." [6] However, an independent assessment by Sargent and Lundy for the National Renewable Energy laboratory (NREL) in 2003 indicates that further advancements to CSP trough technologies are possible without requiring breakthroughs and "significant cost reductions are achievable assuming reasonable deployment of CSP technologies occurs." [7] Table 1 is a summary of anticipated performance trends for parabolic trough technologies based on the Sargent and Lundy study.

Table 1: Performance Trends for Parabolic Trough Systems

		SunLab Cases			S&L Cases		
	Baseline:						
	SEGS VI	Trough 100	Trough 150	Trough 400	Trough 100	Trough 150	Trough 400
Parameter/Year	**1989**	**2004**	**2010**	**2020**	**2004**	**2010**	**2020**
Net Power (Mwe)	30	100	150	400	100	150	400
Solar Field Optical Efficiency	0.535	0.567	0.598	0.602	0.567	0.57	0.57
Receiver Thermal Losses	0.729	0.86	0.852	0.853	0.843	0.81	0.81
EPGS Efficiency	0.35	0.37	0.4	0.4	0.37	0.4	0.4
Electric Parasitic Load	0.827	0.884	0.922	0.928	0.884	0.922	0.928
Power Plant Availability	0.98	0.94	0.94	0.94	0.94	0.94	0.94
Annual Solar to Electric Efficiency (%)	10.6	14.3	17.00%	17.20%	14.00%	15.40%	15.50%
Capacity Factor	22/34%	54%	56%	57%	54%	56%	57%
Thermal Storage (hrs)	0	12	12	12	12	12	12
Solar Field (millions km2)	0.188	1.12	1.477	3.91	1.14	1.63	4.35
Land Area (million km2)	0.635	3.76	4.98	13.189	NG	NG	NG

Source: National Renewable Energy Laboratory

California Energy Commission staff also looked at several other studies to assess performance and cost trends for parabolic trough systems including analyses by Navigant Consulting [24], the Electric Power Research Institute[22] and Solargenix Energy.[8] The other three studies provided similar cost and performance projections.

Performance trends listed in Table 1 use the LUZ SEGS VI facility as a base case. Performance advancements going out to 2020 are based on projections from SunLab [9] and independently by Sargent and Lundy. Generally, only incremental changes are anticipated in trough technology. The most significant changes include addition of thermal storage (up to twelve hours) and an increase in plant capacity from 50 MW net in 2004 to 400 MW net by 2020.[10] By 2010, trough technology facilities are expected to be sized at approximately 150 MW (net) and have capacity factors approaching 55 percent (if thermal storage is used).

The Sargent and Lundy report also looked at cost trends for parabolic trough systems. A summary of the results is listed in Table 2 along with results from an EPRI analysis of near term trough systems (assuming only 4 versus 12 hours of storage). According to

SunLab projections, capital costs are expected to rise nearly 65 percent above the SEGS VI baseline case in the early deployment year (2004), but then drop back to below the baseline by 2010 and fall 25 percent below baseline by 2020. However, these capital cost changes are accompanied by nearly a 2.5 fold increase in capacity factor due primarily to thermal storage.

Table 2: Cost Trends for Parabolic Trough Systems

			SunLab Cases		
	Baseline:	**EPRI**			
	SEGS VI	**Near Term**	**Trough 100**	**Trough 150**	**Trough 400**
Parameter/Year	**1989**	**2004**	**2004**	**2010**	**2020**
Net Power (Mwe)	30	100	100	150	400
Solar Field Optical Efficiency	0.535	NA	0.567	0.598	0.602
Gross Thermal Input (MWt)	88	NA	294	408	1087
Capacity Factor (%)	22%	33%	54%	56%	56%
Annual Solar to Electric Efficiency (%)	10.6%	13.0%	14.2%	17.0%	17.2%
Direct Capital Costs:					
o Structures & Improvements ($/kWe)	84	NA	73	54	41
o Solar Collector System ($/kWe)	1,493	NA	2,497	1,512	1,132
o Thermal Storage System ($/kWe)	0	NA	958	383	383
o Steam Generator or HX ($/kWe)	143	NA	100	74	48
o EPGS ($/kWe)	527	NA	367	293	197
o BOP ($/kWe)	306	NA	213	171	115
Total Direct ($/kWe)	2,553	3,150	4,208	2,487	1,916
O&M ($/kWhr)	0.025	0.017	0.0228	0.0135	0.0097

Source: National Renewable Energy Laboratory

Cost trends from Table 2 were used in a revenue requirement model to generate levelized cost of electricity generation (LCOE) estimates for trough systems going out to 2020. LCOE estimates were generated with and without a $0.018/kWhr production tax credit (PTC) for five years. In addition, LCOE estimates were made with and without the near term EPRI costs. A summary of capital and O&M costs used in the model and the resulting LCOE values are shown in Table 3. LCOE estimates going out to 2020 along with forecasted wholesale electricity prices based on Energy Commission adopted forecasts[11] are shown in Figure 1.

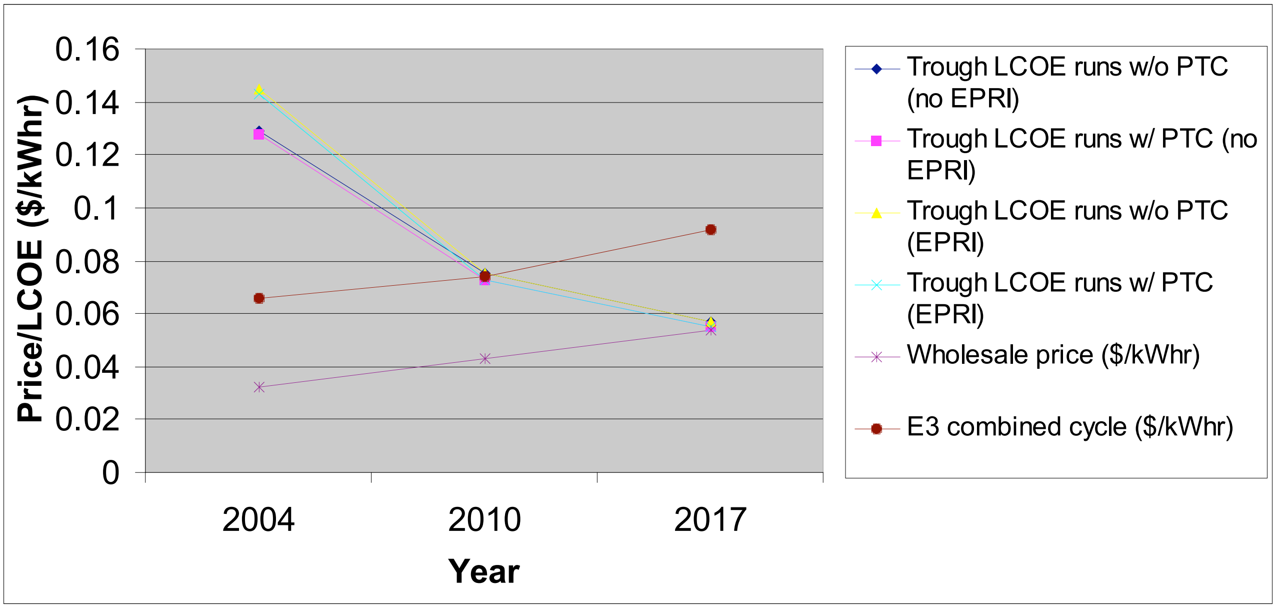
Table 3: Inputs and Results for Trough Systems

Trough LCOE runs (no EPRI)				
Case/	SEGS VI	Trough 100	Trough 150	Trough 400
Year	1989	2004	2010	2020
Net Capacity (MW)	30	100	150	400
Capital Costs ($/kW)	2553	4208	2487	1916
O&M ($/kWhr)	0.025	0.0228	0.0135	0.0097
Capacity Factor (%)	22	54	56	56
LCOE ($/kWhr) w/o PTC	**0.181**	**0.130**	**0.075**	**0.057**
LCOE ($/kWhr) w/ PTC	**0.179**	**0.128**	**0.073**	**0.055**
Trough LCOE runs (EPRI)				
Case/	SEGS VI	EPRI Near Term	Trough 150	Trough 400
Year	1989	2004	2010	2020
Net Capacity (MW)	30	100	150	400
Capital Costs ($/kW)	2553	3150	2487	1916
O&M ($/kWhr)	0.025	0.017	0.0135	0.0097
Capacity Factor (%)	22	33	56	56
LCOE ($/kWhr) w/o PTC	**0.181**	**0.145**	**0.075**	**0.057**
LCOE ($/kWhr) w/ PTC	**0.180**	**0.143**	**0.073**	**0.055**
Wholesale price ($/kWhr)	**0.03**	**0.032**	**0.043**	**0.07**
E3: Combined Cycle ($/kWhr)	NA	**0.0694**	**0.0742**	**0.0915**

Source: National Renewable Energy Laboratory

Based on the projected cost trends, the LCOE for trough systems is expected to fall from current values of approximately $0.14/kWhr to $0.07/kWhr by 2010 and then down below $0.06/kWhr by 2020. As Figure 1 shows, the LCOE values for trough systems do not fall below forecasted wholesale prices until close to 2015. However, trough LCOE values are close to 2010 combined cycle costs projected by Energy and Environmental Economics, Inc. (E3).[12] Moreover, trough systems deployed before 2015 may still be economically competitive based on market price referents (MPR) adopted in California. The revised 2004 baseload MPR is $.0605/kWhr and the peaking MPR is $.1141 kWhr (10 year, the peaking MPR assumes a 12 month, 5x8 delivery).[13]

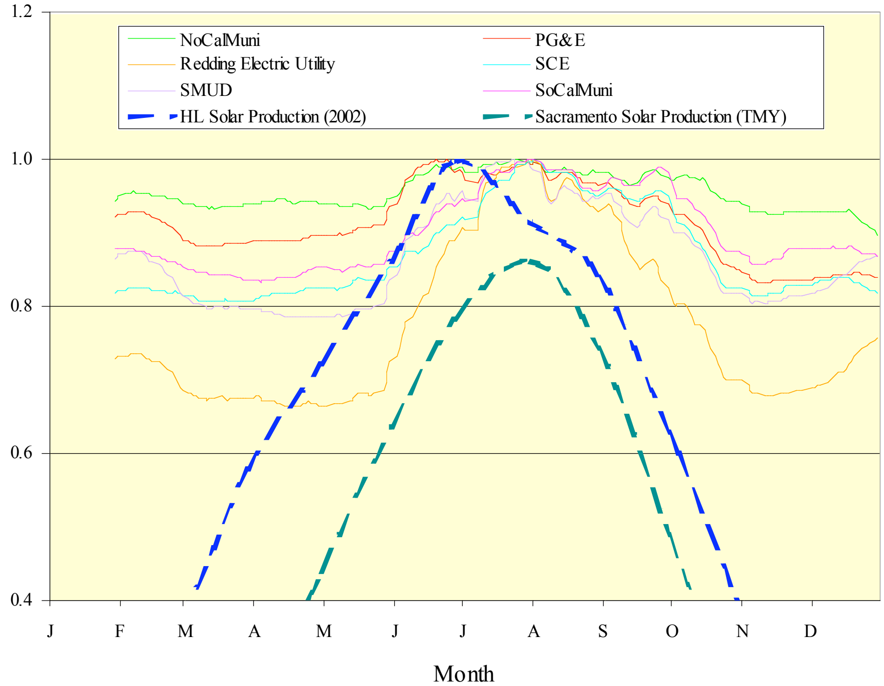
Figure 1: Projected LCOE for Trough Systems



Source: California Energy Commission

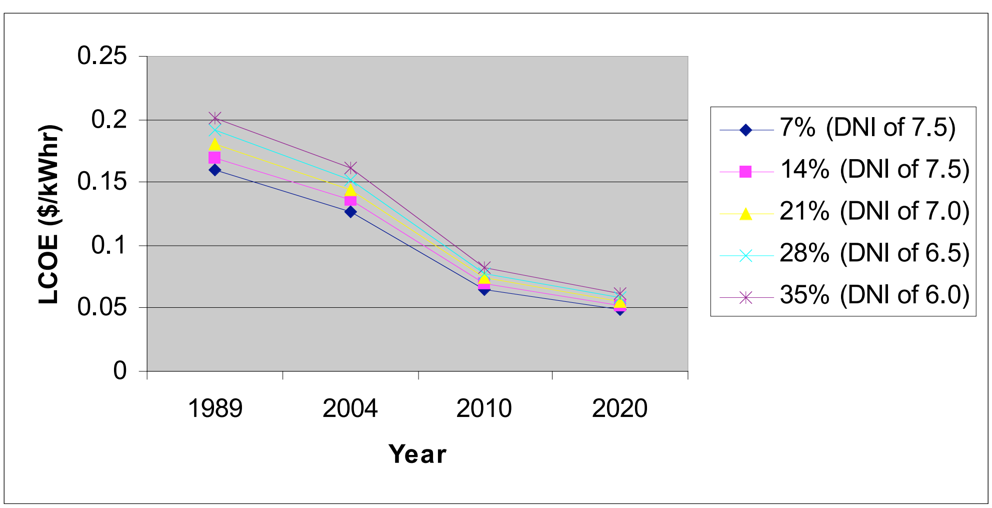
Between 2005 and 2010, trough systems may bid into RPS procurement solicitations based on MPR peaking prices. The ability of trough systems to meet the MPR peaking criteria require they provide power that matches utilities' peak needs. Solargenix has examined the fit between a parabolic trough system deployed at Harper Lake and Sacramento against the demand for a variety of electric utilities in California.[8] The results, shown in Figure 2, demonstrate that parabolic trough systems located with adequate solar resources and with natural gas hybridization or thermal storage can likely meet MPR peaking requirements, and as such can be economically competitive in the RPS. However, the location for siting those facilities to achieve the needed level of solar resource is critical. The performance and cost trends assume a direct normal insolation (DNI) value of 8.05 kWhr-/m^2-day. California Energy Commission staff ran sensitivity levels of the impact of varying DNI on levelized cost. Results are shown in Figure 3. In general, a loss of every 0.5 kWhr-/m^2-day represents nearly a 7 percent increase in the LCOE. Based on these results, locations with DNI values lower than 7.0 kWhr-/m^2-day are not considered economically viable before 2010.

Figure 2: Demand Load Versus Solar Production



Source: Solargenix

Figure 3: Impact of DNI on LCOE



Source: California Energy Commission

Power Tower Facilities

Power tower facilities use towers and two-axis tracking heliostat reflector fields to collect direct beam solar energy at high temperatures. The collected thermal energy is then used to generate steam for a conventional steam turbine. The system uses a circular array of heliostats (large individually tracking mirrors that can change orientation to track the sun's position) to focus sunlight onto a power tower mounted on top of a tower.

Tower power technology is in the development stage, with no commercial projects in operation. The first tower system, Solar One, was constructed in the high desert of Southern California and operated in the mid-1980's. The project used a water/steam system to generate 10 MW of power. In 1992, a consortium of United States utilities banded together to retrofit Solar One. The goal was to demonstrate the technical feasibility of using a molten salt receiver and a thermal storage system. The resulting 10 MW Solar Two Demonstration Project in Daggett, California is the prototype for further United States development and commercialization efforts for power tower systems.

Table 4: Performance Trends for Tower Power Systems

		SunLab Cases				
	Baseline:	**Near Term**		**Mid-Term**		**Long-Term**
	Solar Two	**Solar Tres**	**Solar 50**	**Solar 100**	**Solar 200**	**Solar 220**
Parameter/Year	**1996**	**2004**	**2006**	**2008**	**2014**	**2018**
Power Cycle	Rankine	Rankine	Rankine	Rankine	Rankine	SuperCritical Rankine
Thermal Size (MWt)	42	120	380	700	1,400	1,400
Net Power (MWe)	10	13.65	50	100	200	220
Capacity Factor (%)	21	78	75	73	74	72
Heliostat Size (m2)	39/95	95	95	148	148	148
Heliostat Design	glass/metal	glass/metal	glass/metal	glass/metal	glass/metal	advanced
No. of Heliostats	1,912	2,432	7,463	8,858	17,608	17,851
Solar Field (millions km2)	0.08	0.23	0.71	1.31	2.61	2.64
Collector Efficiency (%)	50.3	56	56.3	56	56.1	57
Annual Solar to Electric Efficiency (%)	7.9	13.7	16.1	16.6	16.9	18.1
Capacity Factor	19	78	76	73	74	73
Thermal Storage (hrs)	3	16	16	13	13	16

Source: National Renewable Energy Laboratory

As with parabolic trough systems, NREL contracted with Sargent and Lundy to make an independent assessment of power tower technology and cost trends.[7] Table 4 summarizes performance trends for power tower technology projected out to 2018. The most significant changes anticipated in tower power technology in the near term are the scale-up of the heliostats, overall solar field size and increased level of thermal storage. By 2010, heliostat size is anticipated to have increased from 39 to 148 square meters (m^2), plant capacity grows from 10 to 100 MW, and capacity factor improves from 19 to 73 percent. Due to the lack of track record on tower power technologies, Sargent and Lundy believe there is a moderate amount of uncertainty that the anticipated performance trends will be achieved.

Cost trends that track the performance trends are shown in Table 5. Sargent and Lundy expect capital costs to drop by over a factor of two from current levels by 2010 primarily through technology advancements, economies of scale and volume production. By 2020, capital costs are expected to drop by a factor of three below current levels.

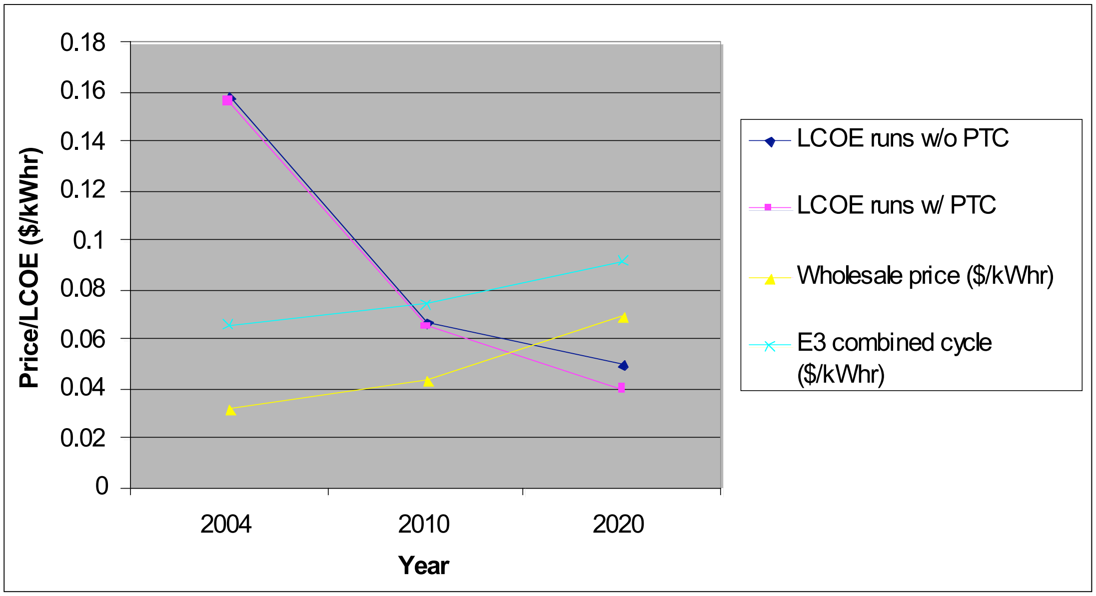
Table 5: Cost Trends for Power Tower Systems

		SunLab Cases				
	Baseline:	**Near Term**		**Mid-Term**		**Long-Term**
	Solar Two	**Solar Tres**	**Solar 50**	**Solar 100**	**Solar 200**	**Solar 220**
Parameter/Year	**1999**	**2004**	**2006**	**2008**	**2014**	**2018**
Net Power (MWe)	10	13.7	50	100	200	220
Thermal Size (MWt)	42	120	380	700	1400	1400
Heliostat Size (m2)	39/95	95	95	148	148	148
Heliostat Field (m2)	81,400	231,000	715,000	1,317,000	2,614,000	2,651,000
Annual Solar-to-Electric Efficiency (%)	7.6	13.7	15.7	16.5	16.8	17.8
Capacity Factor(%)	19	78	76	73	74	73
Capital Cost ($/kWe)	NA	7,180	4,160	3,160	2,700	2,340
O&M Cost ($/kWhr)	NA	0.033	NA	0.008	NA	0.006

Source: National Renewable Energy Laboratory

Cost trends from Table 5 were used in a revenue requirement model to generate levelized cost of electricity generation (LCOE) estimates for tower power systems going out to 2020. LCOE estimates were generated with and without a $0.018/kWhr production tax credit (PTC) for five years. The resulting LCOE estimates are shown against forecasted wholesale prices and E3's project combined cycle costs in Figure 4. Based on the results in Figure 4, LCOE values for tower power systems should be approaching MPR baseload and below MPR peaking costs by 2010. Consequently, towers should be cost competitive by 2010 assuming the cost trends hold true. Note that for the cost trends to hold true, a significant level of tower technology deployment (i.e., 2.6 gigawatts of installed capacity by 2020) must be achieved.[14]

Figure 4: LCOE Costs for Tower Power Systems



Source: California Energy Commission

Parabolic Dish Engines

A parabolic-dish engine system converts direct-beam insolation to electricity by supplying thermal energy to a heat engine located at the focal point of the dish. The dish points directly at the sun using a dual-axis tracking system consisting of a drive motor, gearing and controls. The parabolic shape of the reflective surface, which can be mirrored glass, mirrored film, or a polished metal such as aluminum, focuses the radiation onto the receiver aperture at the engine.

Power units using two-axis tracking parabolic dishes with Stirling engine-driven generators are in a pre-commercial prototype phase. Tracking in two axes is accomplished in one of two ways: (1) azimuth-elevation tracking or (2) polar tracking[15]. Two leading United States manufacturers working on such systems are Stirling Energy Systems (SES) in Phoenix and the Science Applications International Corporation (SAIC) / Stirling Thermal Motors team in San Diego, California and Ann Arbor, Michigan, respectively. SES is currently operating units at a Boeing facility in Huntington Beach, California. Both companies are anticipating future installations in California.

Due to the pre-commercial nature of Dish systems, there is limited performance and cost trend information. DOE has provided technical and cost targets, as shown in Table 6 below, for Dish systems in its 2003 Multi-Year Technical Plan.[16]

Table 6: DOE Performance and Cost Targets for Dish Systems

Plant Characteristics	Units	Calendar year 2003	2007	2025
Solar Resource: Daggett, CA	kWh/m^2-yr	2800	2800	2800
Solar Collector				
Solar Aperture Area	m^2	91	91	88
Projected Glass Area	m^2	88	88	85
Reflectivity	%	92	94	95
Intercept Factor	%	95	97	99
Concentrator Weight	kg/m^2	75	65	30
Power Conversion Unit				
Receiver Type		DIR	DIR	ADV*
Receiver Efficiency	%	90	90	95
Engine Type		KSE	KSE	ADV
Engine Efficiency	%	32	35	42
System Performance Parameters				
Capacity Factor				
Annual Solar Energy Production	kWh/m^2	575	627	754
Annual Total Energy Production	KWh/m^2	575	627	1095
Annual Solar Efficiency Net	%	20	23	26
Annual Capacity Factor	%	24	24	50
Levelized Energy Cost	$/KWh	0.40	0.20	0.06

Considerations:
Hybrid receiver in 2025.

Source: National Renewable Energy Laboratory

Based on the cost targets for Dish systems, they are unlikely to be cost competitive in wholesale markets before 2017. However, Dish systems that can provide distributed generator load for commercial or small industrial applications may be able to compete against retail rates prior to 2017 (especially if they are able to supply heat and power).

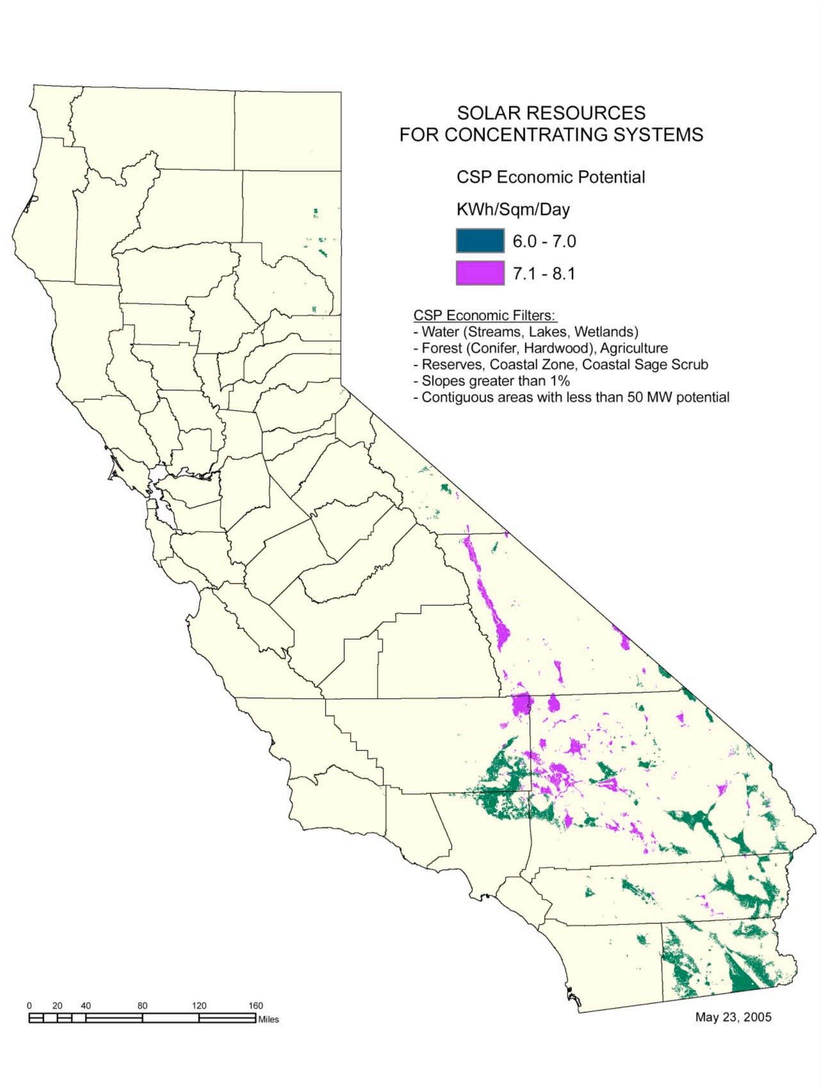
CSP Economic Potential in California

Performance and cost trends indicate that parabolic trough and tower power systems may be economically feasible before 2010. However, in both cases, the solar resource must be greater than 7.0 $kWhr/m^2$-day. The technical potential for CSP presented in the earlier white paper “California’s Solar Resources” was estimated using a number of factors including the available solar resource. When based on a minimum solar resource of 6 $kWhr/m^2$-day, the CSP technical potential in California exceeds 1 million MW of capacity. The economic potential shrinks to approximately 150,000 MW statewide when the minimum solar resource is greater than 7.0 $kWhr/m^2$-day. Table 7 is a breakout of the “first-cut” CSP economic potential at a minimum solar resource of 7.0 $kWhr/m^2$-day at the county level showing net installed capacity and annual energy delivery. Energy delivery estimates assume capacity factors of 25 and 55 percent based on performance trends provided by the Sargent and Lundy report. Figure 5 shows the geographical location of the CSP economic potential. The Sargent and Lundy report and the Multi-Year Solar Technical Plan by DOE assume economic deployment based on a solar resource of 8.0 kWhr/m^2-day or greater. When 8.0 kWhr/m^2-day is used as the minimum solar resource, the CSP economic potential further shrinks to approximately 4500 MW statewide.

Table 7: CSP Economic Potential at County Level (7.0 kWhr/m^2-day)

County	Suitable Area (m2)	Solar Capacity (MW)	Energy (25% CF) (GWhr/yr)	Energy (55% CF) (GWhr/yr)
INYO	112,500,000	5,561	12,179	26,793
KERN	929,920,000	45,967	100,669	221,471
LOS ANGELES	340,980,000	16,855	36,913	81,208
RIVERSIDE	101,180,000	5,001	10,953	24,097
SAN BERNARDINO	1,568,920,000	77,554	169,844	373,656
Totals:	3,053,500,000	150,939	330,557	727,225

Figure 5: Distribution of CSP Economic Potential



Source: California Department of Forestry

CSP Economic Potential and California's Electricity System

While LCOE numbers give a "first-cut" estimate of the CSP economic potential, they do not take into account transmission costs. CSP projects located far from transmission access may have to build and pay for transmission lines to bring their power to the access point. Consequently, CSP facilities located within 10 miles of a substation that can accept power have a considerable economic advantage over facilities that must build transmission to reach suitable access points. Consequently, part of the SVA approach is to identify locations within California's electricity system where it is beneficial to add generation (and similarly identify those locations where additional generation could pose problems).

Davis Power Consultants (DPC)[17] was commissioned by the Energy Commission to identify possible locations within California's transmission and distribution system where capacity or reliability problems (termed "hot spots") might emerge in the future.[18] Power flow analyses were used to identify the "hot spots" under summer, winter and spring peak conditions for 2005, 2007, 2010 and 2017. A more thorough description of the DPC approach, analyses and results can be found in the reports "Draft Report on 2010 and 2017 WTLRs: Task 2.1.3 (DPC Report Number DPC-11)," and "Draft Report on 2010 and 2017 Simulations of California System Hot Spots: Task 2.1.2 (DPC Report Number DPC-10)."

DPC developed a factor called the Weighted Transmission Loading Relief Factor (WTLR) as a single indicator of the effectiveness for mitigating overloads at each bus (substation). The WTLR represents the expected contingency megawatt overload reduction if 1 MW of new generation is injected at that bus. For example, a bus with a WTLR of 4 means that for every 1 MW of installed generation there will be a corresponding 4 MW reduction in the contingency overload. Since there are transmission overloads across transmission lines rated from 69 kV to 500 kV and in different utility control areas, DPC developed a methodology that compares the transmission benefits of locating different power plants at different locations on an unbiased basis.

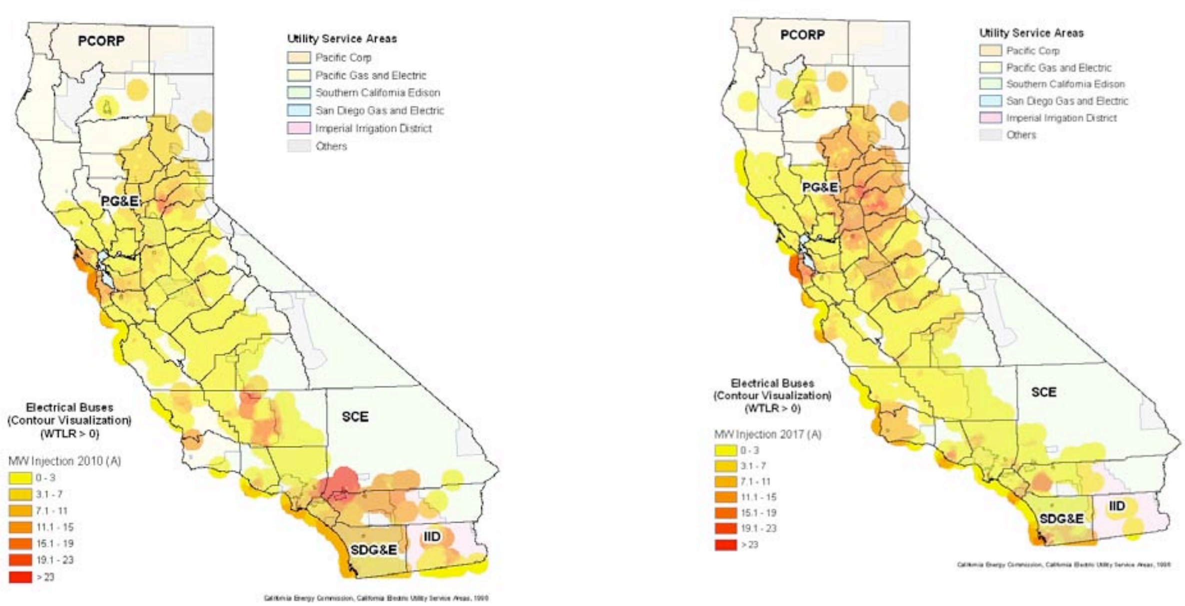
In basic terms, the DPC methodology uses the number of violation occurrences, operating voltage of the element and the average percent overload over all of the occurrences to calculate the WTLR for each element. If all the individual WTLRs are added together, the result is an Aggregated Megawatt Contingency Overload (AMWCO).

The DPC approach is an independent methodology for prioritizing locations for new power plants (conventional or renewable). The approach allows a comparison in the reduction of the AMWCO for generation located at different WTLR locations. For example, assume a substation AMWCO is 10,000 MW and there are two possible projects that can reduce the AMWCO. One plant provides power at 500 kV with a WTLR of 2 that reduces the AMWCO down to 9,500. The second project location provides power at 115 kV with a WTLR of 4 that reduces the AMWCO to 9,000. Based on the DPC approach, the 115 kV site would be selected as the priority location for siting new generation due to its greater reduction in the AMWCO.

An AMWCO is a relative indication of the reliability of the transmission grid. It is not to be confused with the amount of generation or transmission needed to be added to the system. Used in combination, the WTLR indicates the effectiveness of installing new generation at a bus while the AMWCO indicates the overall reduction that the new generator has on the reliability of the entire system.

Figure 6 shows the distribution of WTLRs for California's electricity system at 2010 and 2017 summer peak conditions based on the DPC approach. The power flow analyses assumed that all power plants and transmission lines that have been approved for construction will be built.

Figure 6: Potential "Hot Spots" for 2010 and 2017

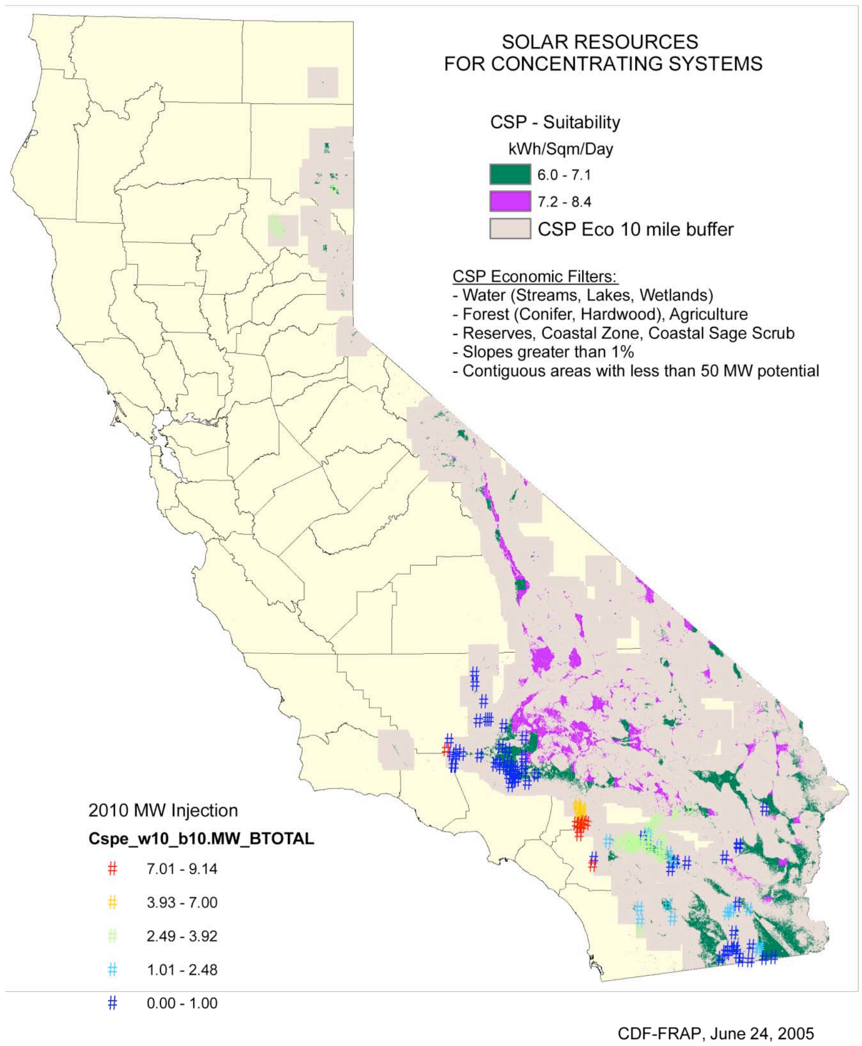


Source: California Department of Forestry

As Figure 6 shows, "hot spots" are predominately located in the Bay Area, urban centers in southern California and the Sacramento region extending into the Sierra's by 2010. However, the "hot inland" areas within California's Central Valley also face possible grid problems. By 2017, grid congestion problems continue to worsen in the greater Sacramento region as well as in the Central Valley. Successfully addressing congestion or capacity problems at the identified WTLR locations can provide the greatest level of benefit to California's electricity system. In addition, identifying the magnitude of the problems posed at the WTLRs and the manner in which WTLR problems are inter-related enables an approach to be developed that solves near term problems while simultaneously building a set of solutions that address longer term grid issues.

GIS tools were used to overlay WTLR locations for 2010 on top of the CSP resources as shown in Figure 7. Intersections between CSP solar resource locations and WTLR locations greater than zero occurred in five counties:

Figure 7: CSP Resources and WTLR Locations for 2010



Source: California Department of Forestry

Riverside, San Bernardino, Imperial, San Diego and Plumas. These locations represent areas where sufficient solar resources exist to be economically developed, and because of their proximity to substations with "appropriate WTLR values," can help address hot spots in California's electricity system. While economic CSP resources exist in Los Angeles, Kern and Inyo counties, these locations did not coincide with WTLRs greater than zero. Table 8 lists the CSP economic MW potential by county that intersected substations with the required WTLR value. The total amount of economic CSP solar resource that is located within 10 miles of suitable transmission access locations is a little less than 1100 MW. These CSP projects are located in close proximity to substations that can provide transmission access. Consequently, development of these projects is assumed to require no significant transmission capital costs.

Table 8: Economic CSP Intersecting WTLR > 0 for 2010

County	DNI (kWhr/m2-day)	CSP Potential Intersecting WTLR > 0 (MW)	Economic CSP Potential Intersecting WTLR > 0 (MW)
Riverside	> 7.0	599	599
San Bernardino	> 7.0	477	477
Imperial	< 7.0	66	0
San Diego	< 7.0	35	0
Plumas	< 7.0	24	0
Totals:	NA	1201	1076

Electricity System Impacts of Developing CSP Economic Potential

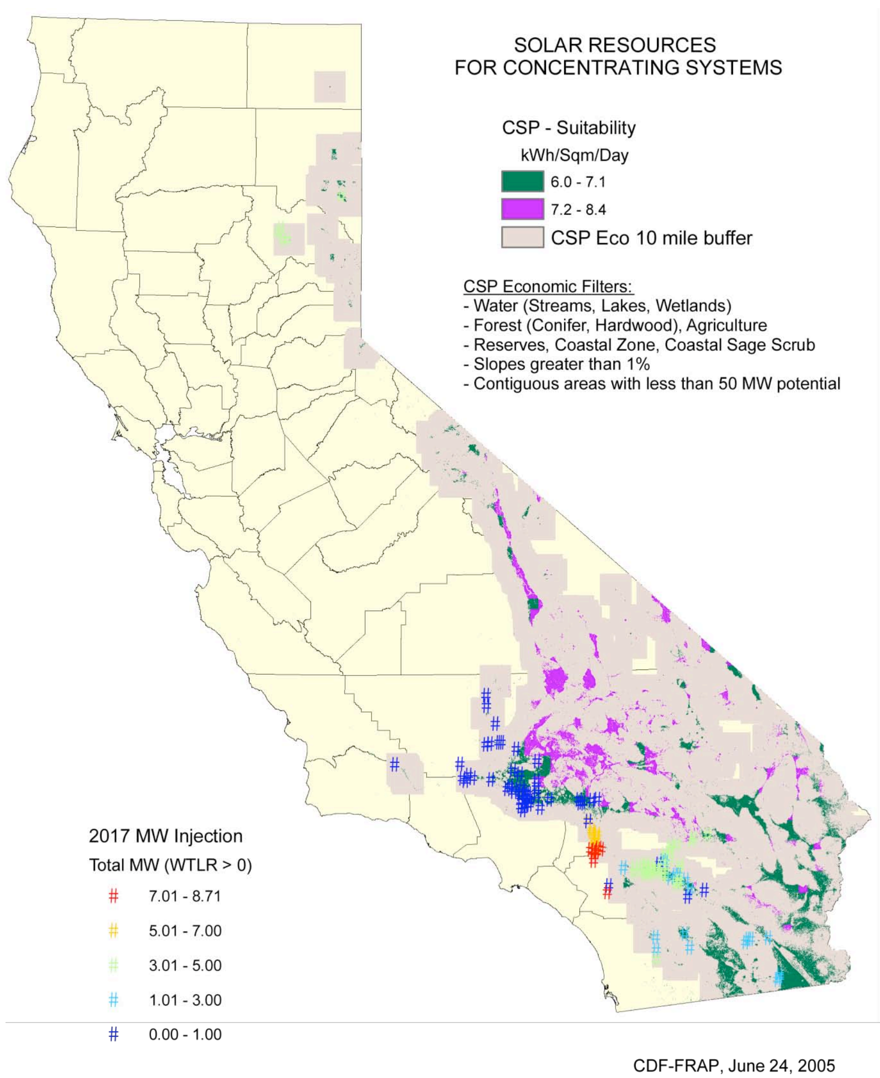
Using power flow analysis tools, DPC simulated the addition of CSP economic generation potential into California's electricity system at 2010.[19] The CSP generation was simulated for summer peak conditions. Using summer peak conditions was considered a conservative, worst-case approach to addressing grid problems while also meeting the state's RPS goals. In particular, California's electricity system suffers primarily from difficulties in meeting summer peak demand. In addition, renewable generation that is intermittent in nature, like solar, would likely have difficulties in addressing peak demand. Consequently, an approach that targeted meeting RPS goals while addressing summer peak was considered to be the most conservative test of deploying renewable generation. System reliability impacts were assessed using DPC's AMWCO approach. Results of DPC's power flow simulations are shown in table 9. The results of table 9 show that development and deployment of slightly less than 1100 MW of CSP generation that is economically feasible prior to 2010 has significant net benefit to California's electricity system. More specifically, deploying 599 MW of CSP in Riverside County at the intersected WTLR locations provides a net benefit to the grid equal to 1,794 MW of power. Similarly, deploying 447 MW of CSP in San Bernardino County provides the equivalent of 1,569 MW. Additional information on the specific locations of the substations and their characteristics, along with more detailed maps showing the WTLR distributions can be found in the DPC report "Final Report on Concentrated Solar MW Solutions for 2010: DPC Report Number DPC-16, December 20, 2004."[19]

Table 9: Results of Power Flow Analysis of CSP Generation

Parameter/County	Riverside	San Bernardino
Contingencies	102	117
Violations	147	159
AMWCO	3,761 MW	3,986 MW
AMWCO Benefit	-1,794 MW	-1,569 MW
MW Installed	599 MW	447 MW
Impact Ratio	-2.99	-3.51

Figure 8 shows the overall WTLR and CSP resource distributions for 2017. Based on these distributions, DPC added 276 MW of CSP potential (199 MW in Riverside County and 77 MW in San Bernardino County) into the 2017 mix.

Figure 8: WTLR and CSP Distribution for 2017



Solar Photovoltaics

Performance and Cost Trends

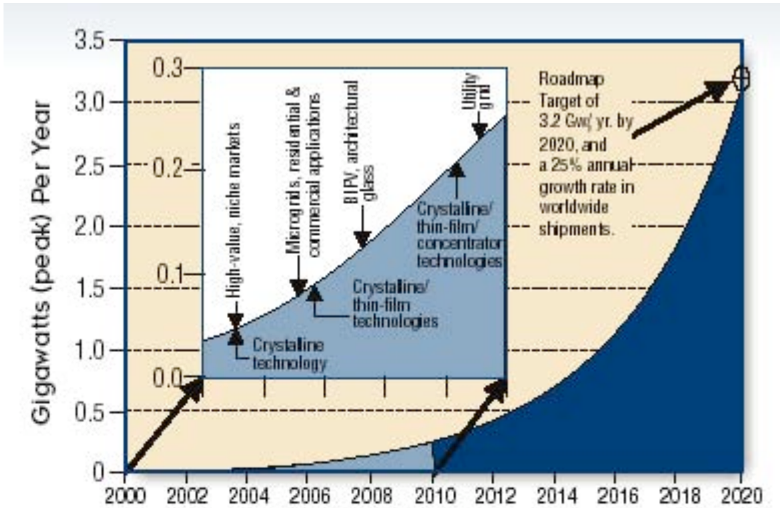
PV systems are solid-state, semiconductor-based devices that convert radiant energy (light) directly into electricity. In contrast to CSP technologies, PV systems can use direct beam, scattered and reflected sunlight to generate electricity. Consequently, PV systems have a potentially broader geographical range over which they can be employed than do CSP systems.

PV systems can be deployed at utility-scale sizes as dedicated power plants or at smaller scale sizes as distributed generation systems. Studies by Pacific Gas and Electric in the 1980's indicated the technical and economic challenges facing PV used in a central station approach.[20] More recently, flat-plate PV systems are being mounted on rooftops to help offset electricity demand at commercial buildings and homes. Since 1981, over 100 MW of rooftop PV systems have been installed in California.[21] Such distributed PV systems offer the potential of being an attractive power solution for congested urban areas where land premiums are too high to accommodate power plants with large footprints, and where the noise and emissions from a conventional fossil-fueled power plant might pose unacceptable impacts.[22]

Future development of PV technologies and markets has been addressed by the United States PV industry in its 2000 PV Industry Roadmap.[23] Figure 9 shows the anticipated market applications and associated PV technologies expected by the industry. High value niche applications using single and polycrystalline PV technologies are expected to dominate the PV market throughout the early 2000's. By the mid-2000's, small-scale residential and commercial applications tied into microgrids are expected to emerge strongly into the marketplace using both crystalline and thin film technologies. PV concentrator technologies and utility-scale applications are not expected to become strong market contenders until after 2010.

The Department of Energy has also investigated cost and performance trends for PV technologies in the Solar Multi-Year Technical Plan.[16] Table 10 reflects targeted costs for utility-scale (i.e., 2 to 20 MW) flat plate PV systems between 2003 and 2020. Based on these cost projections, the LCOE for utility-scale, flat-plate PV applications will be close to \$0.20/kWhr by 2010, and will fall below \$0.10/kWhr by 2020. An independent assessment from EPRI shows similar, but somewhat more optimistic cost reductions.[22]

Figure 9: United States PV Industry Roadmap



Source: National Renewable Energy Laboratory

Table 10: DOE Cost Trends for Utility-Scale PV Systems

System Element	Units	2003	2007	2020
Design	$\$/W_{ac}$	0.25	0.15	0.10
Module Price	$\$/W_{p,dc}$	4.80	2.50	1.00–1.50
Direct cost/power	$\$/W_{p,dc}$	3.00	1.65	0.33–0.50
Conversion efficiency	%	14	15	15–20
Direct cost/area	$\$/m^2$	420	250	50–100
Inverter Price	$\$/W_{ac}$	1.10	0.50	0.30
DC-AC conversion efficiency	%	94	96	97
Replacement	Years	5	10	20
Other BOS	$\$/W_{ac}$	0.85	0.60	0.40
Installation	$\$/W_{ac}$	2.50	1.50	0.50
INSTALLED SYSTEM PRICE	$\$/W_{ac}$	6.20–9.50*	5.20	2.30–2.80
System Efficiency	%	11.5	14	16
Lifetime	Years	20	20	30
Degradation	%/Yr	1–2	1-2	1
O&M cost	$\$/kWh_{ac}$	0.08	0.02	0.005
LEVELIZED ENERGY COST	$\$/kWh_{ac}$	0.25–0.40*	0.22	0.8–0.10

Considerations:
LEC is cost to consumer.
2003 numbers taken from example of Figure 4.1.1-3.
LEC is dependent on solar resource (2000 kWh/m^2/yr assumed here).
2003 data assume retrofit market; 2007 and 2020 are for new construction.
O&M primarily based on one inverter replacement every 5 years for 2003 figures; every 10 years for 2010 and 2020 figures.
*The ranges reflect the variability in calculations including various incentives and financing assumptions. LECs have been reported previously for year 2000 with incentives included.

Source: National Renewable Energy Laboratory

Performance and cost trends for small-scale PV technologies used in residential and commercial applications have been looked at by DOE and Navigant Consulting.[16,24] A summary of performance and cost trends from Navigant is shown in table 11, while the DOE results are shown in table 12.

Table 11: Residential PV Cost Trends

	2003	2008	2013
Parameter/Year	**Wafer**	**Wafer**	**Wafer**
System efficiency (%)	12	14.5	16.5
Residential (3 kWp)			
- Installed Price ($/kWac)	9,000	7,000	5,000
- O&M ($/kWp-yr)	15	13	10
Commercial (250 kWp)			
- Installed Price ($/kWac)	6,500	5,000	4,000
- O&M ($/kWp-yr)	13	11	9

Source: Navigant

Table 12: Residential PV Cost Trends

System Element	Units	2003	2007	2020
Design	$\$/W_{ac}$	0.25	0.15	0.10
Module Price	$\$/W_{p,dc}$	4.80	2.50	1.00–1.50
Direct cost/power	$\$/W_{p,dc}$	3.00	1.65	0.33–0.50
Conversion efficiency	%	14	15	15–20
Direct cost/area	$\$/m^2$	420	250	50–100
Inverter Price	$\$/W_{ac}$	1.10	0.50	0.30
DC-AC conversion efficiency	%	94	96	97
Replacement	Years	5	10	20
Other BOS	$\$/W_{ac}$	0.85	0.60	0.40
Installation	$\$/W_{ac}$	2.50	1.50	0.50
INSTALLED SYSTEM PRICE	$\$/W_{ac}$	6.20–9.50*	5.20	2.30–2.80
System Efficiency	%	11.5	14	16
Lifetime	Years	20	20	30
Degradation	%/Yr	1–2	1-2	1
O&M cost	$\$/kWh_{ac}$	0.08	0.02	0.005
LEVELIZED ENERGY COST	$\$/kWh_{ac}$	0.25–0.40*	0.22	0.8–0.10

Considerations:
LEC is cost to consumer.
2003 numbers taken from example of Figure 4.1.1-3.
LEC is dependent on solar resource (2000 kWh/m^2/yr assumed here).
2003 data assume retrofit market; 2007 and 2020 are for new construction.
O&M primarily based on one inverter replacement every 5 years for 2003 figures; every 10 years for 2010 and 2020 figures.
*The ranges reflect the variability in calculations including various incentives and financing assumptions. LECs have been reported previously for year 2000 with incentives included.

Source: National Renewable Energy Laboratory

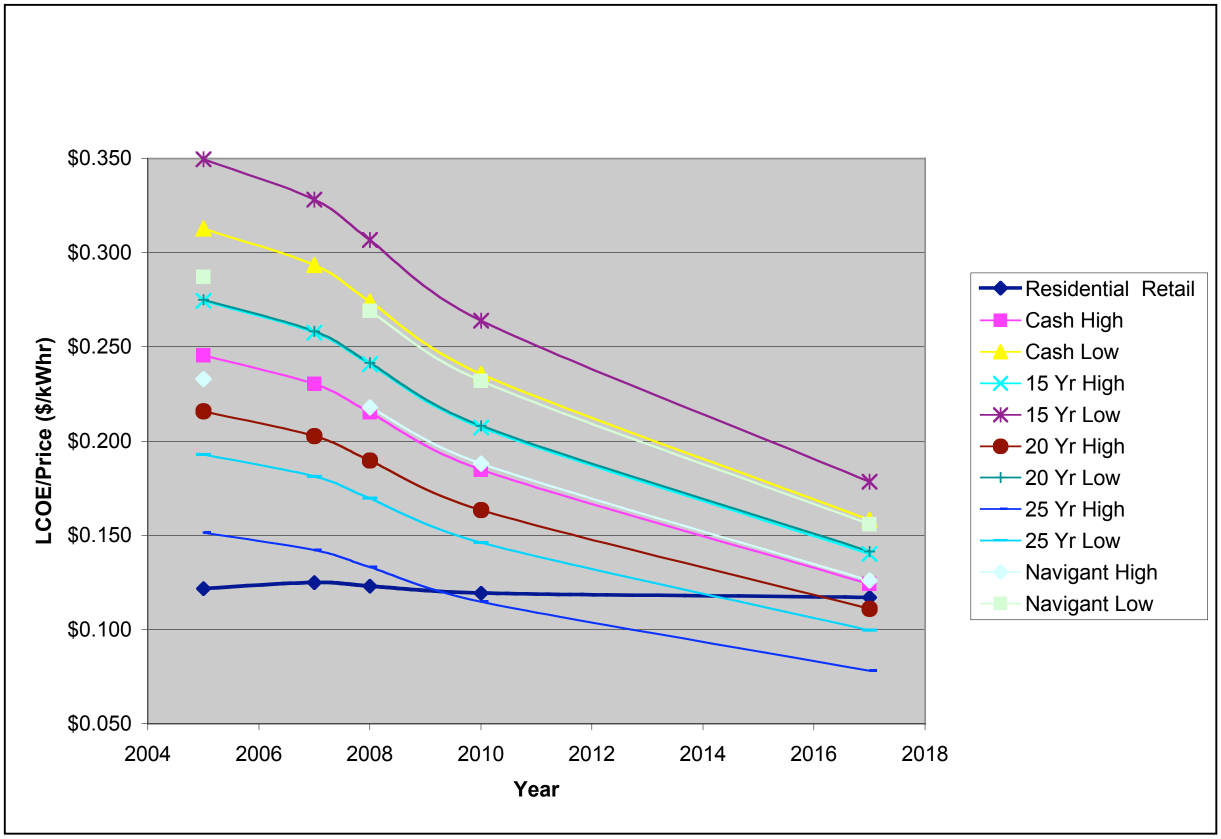
Cost trends from Tables 10 through 12 were used in a revenue requirement model to generate levelized cost of electricity generation (LCOE) estimates for PV systems going out to 2017. LCOE estimates were generated for residential systems using the assumptions listed in Table 13. In addition, the LCOE estimates assumed a 25-year life on the system, inverter replacement every ten years, and financing of the system at 5% interest under various financing terms. Estimates were developed for two scenarios: one assuming no State rebates and no income tax credit; the other assuming availability of State rebates and an income tax credit (2005 only) of 7.5 percent.

Table 13: Assumptions for Residential PV LCOE Cost Estimates

Basic Assumptions	Year 2005	Year 2010	Year 2017
Capital Cost			
Cells/Modules	3,775	2,831	1,888
Balance of Plant	2,644	1,983	1,322
Engineering Fee	642	482	321
Contingency+Owners Cost	939	704	469
Total Capital Cost ($/kW)	8,000	6,000	4,000
Net Plant Capacity (kW)	3	3	3
Incremental capital cost (after year 10) ($/kW)	406	292	175
Incremental capital cost (after year 20) ($/kW)	208	125	125
State Rebate ($/kW)	2800	800	0
Capacity Factor	CF = 20% for High Insolation and 15.7% for low Insolation		

LCOE results for residential PV applications are shown and compared against statewide average residential retail rates and Navigant LCOE results in Figure 10. In general, the LCOE values for residential PV systems remain higher than the forecasted average retail rates. However, residential PV systems are currently cost-competitive when used with tiered retail rates, time of use (TOU) rates, or when financed under a long-term mortgage approach. For widespread adoption in the near-term, residential PV will continue to rely on public assistance.

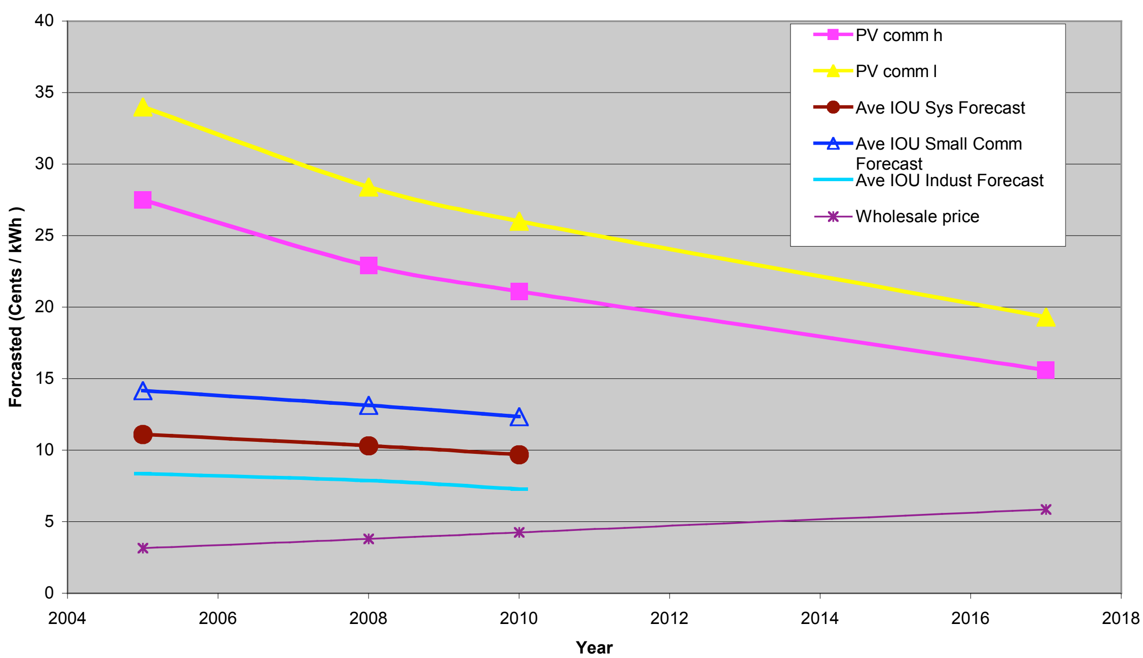
Figure 10: LCOE Results for Residential PV



Source: California Energy Commission

Cost trends from Table 11 were also used in the revenue requirement model to generate LCOE estimates for commercial building PV systems going out to 2017. LCOE results as shown in figure 11 are compared against wholesale electricity projections as well as against forecasted average rates for industrial and small commercial IOU customers. Generally, the LCOE for commercial building PV systems significantly exceeds forecasted electricity rates. However, as with residential PV systems, commercial building PV systems are currently cost-competitive under tiered rates, TOU rates and with special financing mechanisms.

Figure 11: LCOE for Commercial Building PV versus Forecasted



Rates

Source: California Energy Commission

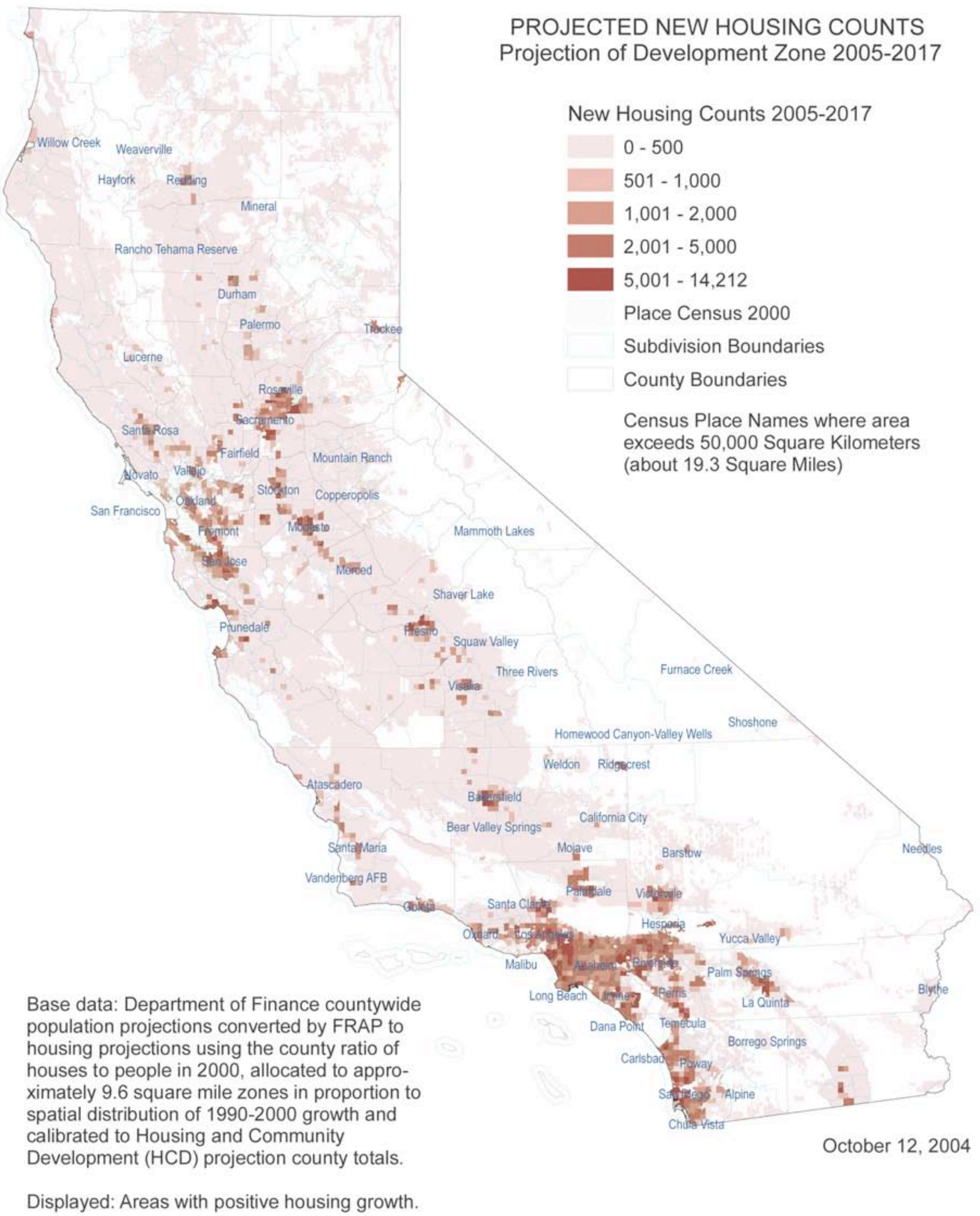
Solar PV Economic Potential and California's Electricity System

Based on LCOE projections, PV systems for both residential and commercial applications are economically more feasible for wider spread adoption in the near term with public incentives. In California, the Million Solar Roofs Initiative (Senate Bill SB1, Murray) is intended to provide incentives sufficient to deploy solar PV systems on fifty percent of new homes in thirteen years. Analysis conducted by Kema-Xenergy indicates that under a Million Solar Roofs Initiative approach, California could deploy nearly 500 MW of solar PV systems by 2010 and over 2000 MW by 2017.[25]

Aside from public incentives, deployment of PV systems could occur in accordance with TOU rates that reward the ability of PV systems to provide benefits to electric utilities. Under a TOU rate approach, PV systems will provide the highest value (and assumedly be most economically competitive) in electricity system locations suffering from congestion or capacity problems. Consequently, GIS tools were used to find locations where residential PV deployment would coincide with “hot spots” to potentially help address grid problems. In addition, the assumption was made that residential PV deployment would occur in urban areas with the highest housing growth

Energy Commission staff worked with California Department of Forestry (CDF) in developing a list of projected new housing development sites by county for 2010 and 2017. The counties with projected new housing development are shown in Figure 12. The total number of projected new homes by 2010 and 2017 were 1,114,226 and 2,443,423, respectively. If each new home had a 2 kW solar installation, then the total potential residential solar generation would be 2,228 MW and 4,886 MW for 2010 and 2017, respectively. However, only 500 MW of solar PV is deployed by 2010 based on a conservative approach of assuming PV systems are deployed only in accordance with the Million Solar Roof projections.

Figure 12: Highest Housing Growth Regions California 2005-2017



Electricity System Impacts of Developing Solar PV Economic Potential

DPC used power flow analysis tools to evaluate the impact of deploying 500 MW of residential PV in high housing growth areas. California Department of Forestry (CDF) supplied DPC a list of buses (substations) for each selected high growth area (682 buses total). DPC cross-referenced each bus from CDF list of buses in the 2010 Summer Base case. The 682 buses were then sorted into three categories; (1) the bus does not exist in the case; (2) the bus has no existing load, or (3) the bus has a load. The buses that had no load or did not exist in the case were deleted from the list leaving only buses with existing load (i.e., a narrowed down list to 315 buses).

Next, DPC deleted buses with loads of 39 MW and lower. The reason for deleting buses with less than 40 MW was to have a more manageable list. For example, distributing 0.25 MW on a bus that has a load of 1 MW would not be as effective as distributing 2 MW on a bus with 75 MW of load. This reduced the list to 129 buses, making a smaller amount of generation to be distributed among the WTLR locations.

DPC ran three power flow simulations to assess the grid impacts of residential PV deployment. The first power flow model verified the base case assumptions and established the base case parameters for the number of contingencies, violations, and the AMWCO. The contingency analysis used the thermal limit B for the lines and transformers and the post contingency state for each contingency was obtained using full AC power flow solutions. For the second simulation, 535 MW was distributed across the 129 buses to simulate the residential solar distribution.

Residential PV deployment was assumed to continue out to 2017 at a similar growth rate as for the 2010 case. Rather than distributing more MW across California for residential solar development, DPC concentrated the solar development at the already selected high growth housing areas. A third power flow model was run simulating the increase in solar generation (1070 MW by year 2017).

Results of the power flow simulations are shown in Table 14. In general, deployment of 500 MW of residential PV in the highest residential growth areas of the state by 2010 provides a net two-to-one benefit to California's electricity system. Deployment of 1070 MW of residential PV by 2017 provides the same level of grid benefit.

Table 14: Impacts of Deploying 500 MW of Residential PV by 2010

	2010 Summer Case	535 MW	1070 MW
Contingencies:	371	346	320
Violations:	580	556	520
AMWCO:	16258 MW	15193 MW	14082 MW
AMWCO Benefit		-1,065 MW	-2,176 MW
Impact Ratio:	--	-1.99 MW to 1 MW	-2.03 MW to 1 MW

Conclusions

Concentrating Solar Power

Based on cost and performance trends, California has over 150,000 MW of economically viable CSP potential if the minimum developable solar resource is 7 kWhr-/m^2-day. The economic CSP potential drops to approximately 4500 MW if the minimum developable solar resource is 8 kWhr-/m^2-day.

CSP systems located in areas with high insolation and that employ thermal storage or natural gas hybridization could feasibly be cost-competitive in RPS solicitations based on MPR prices.

By 2010, approximately 1100 MW of economic CSP systems could be located in close proximity to substations capable of accepting generation and which represent “hot spots” in the state’s electricity system. CSP systems located in close proximity to these substations would not need to pay for significant new transmission lines to bring their power into the grid.

Power flow analyses show that bringing in the 1100 MW of CSP generation at the selected substations by 2010 will result in an electricity system benefit of approximately 3400 MW or a system benefit ratio of over 3 to 1 for every MW of installed CSP generation.

At an estimated installed cost of approximately $2500/kW, the capital investment of deploying 1100 MW of CSP generation by 2010 would be $2.75 billion.

Solar Photovoltaic Resources and Technologies

Under business-as-usual conditions, LCOE values for grid connected residential PV systems are expected to be close to $0.20/kWhr by 2010 and fall below $0.10/kWhr by 2020. Similarly, LCOE values for grid connected commercial building PV systems are expected to be above $.020/kWhr by 2010 and above $0.15/kWhr by 2017.

PV systems can be cost effective in California on the basis of tiered rates, TOU rates or financing arrangements that are either longer term or capture non-energy benefits from grid connected PV systems. However, more near-term and widespread adoption of PV systems will likely rely on public incentives.

Under the Million Solar Roofs Initiative, approximately 500 MW of PV systems could be deployed in California by 2010 and over 2000 MW by 2017.

Power flow analyses show that locating 500 MW of grid connected PV systems in the highest housing growth areas of the state can provide over 1000 MW of electricity system benefits.

Endnotes

[1] California Energy Commission, April 2005, *2004 Net System Power Calculation*, Sacramento, CA CEC-300-2005-004

[2] California Energy Commission, May 8, 2003, *Energy Action* Plan, www.energy.ca.gov/energy_action_plan

[3] Simons, G. and McCabe, J., California Energy Commission, *California Solar Resources: Draft Staff Paper,* CEC-500-2005-072-D, April 2005

[4] Davis Power Consultants, *Strategic Value Analysis for Integrating Renewable Technologies in Meeting Target Renewable Penetration,* draft report to the Energy Commission, June 22, 2005

[5] Single axis tracking systems follow the sun by rotating around one axis. A trough solar field collector axis is typically orientated north-south and tracks the sun from east to west during the day. Dual-axis tracking systems such as used with power towers or parabolic dishes point the collector or mirrors directly at the sun.

[6] National Research Council, *Renewable Power Pathways: A Review of the U.S. Department of Energy's Renewable Energy Program,* NRC-2000

[7] Sargent & Lundy LLC Consulting Group (for the National Renewable Energy Laboratory), *Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts, NREL/SR-550-34440, October 2003*

[8] Solargenix Energy (for the California Energy Commission), *Solar Thermal Parabolic Trough Electric Power Plants for Electric Utilities in California,* draft report, February 2005

[9] SunLab represents a combination of researchers from Sandia National Laboratories and the National Renewable Energy Laboratory working together on concentrating solar power technology development

[10] It should be noted that the US trough industry is pursuing near term deployment of natural gas hybrid facilities that will not use thermal storage as a lower risk approach.

[11] California Energy Commission, *Electricity Infrastructure Assessment,* 100-03-007F, May 2003

[12] Energy and Environmental Economics, *California Public Utilities Commission Avoided Cost Proceedingsin Rule Making 04-04-025,* from http://www.ethree.com/cpuc_avoidedcosts.html, April 7, 2005

[13] California Public Utilities Commission, *Order Instituting Rulemaking to Implement the California Renewables Portfolio Standard: Rulemaking 04-04-06,* April 22, 2004

[14] Adding 2.6 gigawatts of tower technology by 2020 requires adding over 170 MW of tower systems every year for the next 15 years.

[15] In azimuth-elevation tracking, the dish rotates in a plane parallel to the earth (azimuth) and in another plane perpendicular to it (elevation). In the polar tracking method, the collector rotates about an axis parallel to the earth's axis of rotation. The other axis of rotation, the declination axis, is perpendicular to the polar axis.

[16] U.S. Department of Energy, Energy Efficiency and Renewable Energy Program, *Solar Energy Technologies Program Multi-Year Technical Plan,* 2003

[17] Davis Power Consultants (DPC) team is comprised of staff from Davis Power Consultants, PowerWorld Corporation and Anthony Engineering. Reference to DPC in this report is the three consulting companies listed above.

[18] Davis Power Consultants under McNeil Technologies Contract with the California Energy Commission, Contract 500-00-031

[19] Davis Power Consultants (for the California Energy Commission), *Strategic Value Analysis of Renewable Power Technologies for Concentrated Solar Generation: Task 2.1.3-Final Report on Concentrated Solar MW Solutions (2010), DPC Report Number DPC-16,* December 20, 2004

[20] Wenger, Howard, et. al, Pacific Gas and Electric: Department of Research and Development, *Proceedings of the Twenty-first IEEE Photovoltaic Specialists Conference: Carrisa Plains PV Power Plant Performance*, 1990

[21] California Energy Commission, Emerging Renewables Program, *Amount of Grid-Connected Solar Photovoltaics (PV) in California, 1981 to Present,* *http://www.energy.ca.gov/renewables/emerging_renewables.html, April 2005*

[22] Electric Power Research Institute, December 2004, *Renewable Energy Technical Assessment Guide-TAG-RE:2004*, Report number 1008366

[23] U.S. Photovoltaic Industry Steering Committee (reprinted by the National Renewable Energy Laboratory for the U.S. Department of Energy), *The U.S. Photovoltaic Industry Roadmap,* December 2000 (reprinted in 2003)

[24] Navigant Consulting, *The Changing Face of Renewable Energy: A Multi-Client Study,* June 5, 2003

[25] Blunden, Julie, Kema-Xenergy, *Million Solar Homes Initiative Penetration and Costs: Draft,* August 3, 2004. The estimated cumulative capacity of PV by 2010 was 475 MW.