GEOTHERMAL STRATEGIC VALUE ANALYSIS

IN SUPPORT OF THE
2005 INTEGRATED ENERGY POLICY REPORT

Elaine Sison-Lebrilla
Valentino Tiangco
Energy Generation Research Office
Energy Research and Development Division
California Energy Commission

DRAFT STAFF PAPER

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Abstract

California has the largest geothermal potential of any state in the nation. According to a 1978 United States Geological Survey (USGS) report, California has an identified geothermal gross potential of 12,000 megawatts (MW). California also has the largest geothermal production and technical potential of any state in the nation with an installed gross capacity of 1,870 megawatts (MW) and an estimated technical potential generation capacity of 4,825 MW. Even though geothermal electricity generation has declined in the past decade, an estimated 2,955 MW of generating capacity from geothermal may still be available for development. Using the strategic value analysis (SVA) methodology, this estimate can be further refined based on economic and location filters. Certain drivers have emerged to encourage the development of geothermal resources. The California Legislature adopted the Renewable Portfolio Standard (RPS) and the federal government has made a production tax credit (PTC) available to new geothermal generation facilities. Geothermal is a base load resource, and developing currently untapped geothermal resources can contribute significantly to RPS goals.

Keywords

Geothermal, dry steam resource, liquid dominated resource.

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Additional Staff Contributors
Energy Generation Research Office
Namita Bhatt

Introduction

California has a tremendous supply of renewable resources that can be harnessed to provide clean and naturally replenishing electricity supplies for the state. Renewable resources, currently provide approximately 11 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 so as to achieve a 20 percent renewable mix by no later than 2017. More recently, the California Energy Commission, the California Public Utilities Commission and the California Power Authority approved the Energy Action Plan (EAP), which accelerated the 20 percent target date to 2010.[2]

A 1978 USGS report[3], identified California with a gross geothermal potential of 12,000 megawatts (MW). This staff paper provides estimates of the economically viable geothermal resources located within California and potentially available to meet the RPS and EAP goals. These estimates are the results of a project known as the strategic value analysis (SVA). This paper updates and expands upon the resource information provided in the staff paper, *California Geothermal Resources Staff Paper,* Publication Number CEC-500-2005-070.

Geothermal Strategic Value Analysis

In 2002, the Public Interest Energy Research (PIER) Renewables Program undertook a project known as the Strategic Value Analysis (SVA). It's purpose was to guide the program's efforts to fund geothermal electric generation RD&D. After passage of the RPS, the SVA assisted in California's RPS implementation. The SVA was viewed as a tool to provide a logical approach to integrating more renewable energy generation into California's electricity system while simultaneously providing non-energy benefits (e.g. environmental, economic etc.). It is a multi-phased effort combining renewable resource assessment, state-of-the-art power flow analysis, and filtering criteria to identify a set of development priorities and sites within a GIS platform. The results also address the magnitude and timeframe for transmission and distribution upgrades to California's electrical system to enable the addition of new renewable generation.

The SVA strives to develop a logical approach to integrating future geothermal capacity into the California transmission grid by:

- Looking at the economics and timeframe for the development of geothermal for maximum public benefits.
- Evaluating points of high strategic value to the grid.
- Providing significant non-energy benefits to the state.
- Providing solutions that help prioritize transmission needs that could defer transmission upgrades.

The SVA team consists of Energy Commission staff, and consultants providing resource assessments, power flow simulation and analysis, and data analysis. The primary consultants involved in the geothermal portion of the SVA are GeothermEx, Davis Power Consultants (DPC), McNeil Technologies, and the California Department of Forestry (CDF). This section provides a description of the state's SVA geothermal resources approach.

- Identification and Qualification of the Resource.
- Calculation of the Cost of Geothermal Electricity Generation.
- Addition of New Geothermal Resource to the Grid.

Resource Identification and Qualification[4]

In July 2002, the Energy Commission executed a Public Interest Energy Research Program (PIER) contract with the Hetch Hetchy Water and Power Division of the San Francisco Public Utilities Commission (Hetch Hetchy/SFPUC) to fund studies and projects relating to renewable energy. GeothermEx, Inc. (GeothermEx) was retained by Hetch Hetchy/SFPUC to provide a geothermal resource assessment for California and western Nevada. This section summarizes the findings of GeothermEx on the resource assessment for California.

GeothermEx used prior research, exploration, and development results available in the public domain. They also used data and information released by some developers into the public domain for this study. Three baseline conditions were used to determine the geothermal resource areas included in this assessment: geographic location, resource temperature, and evidence of a discrete resource. In California, 22 geothermal resource areas were included in the assessment.

Among the various geothermal resource areas, the amount and quality of technical data are extremely variable. A uniform set of required resource criteria therefore needed to be quantified to determine commercial feasibility for each resource area. For each selected reservoir values for the following criteria were obtained or reasonably estimated: temperature, area, thickness, porosity, and resource recovery factor.

To better capture the uncertainty of each resource, the minimum, most likely and maximum values, were used for each criterion. These values were then used in probabilistic simulation, (based on Monte Carlo random-number sampling,) to calculate estimated generation capacity based on accessible heat at the resource area. Because the generation capacity is estimated based on calculated heat in place, there is no guarantee that sufficient permeability exists to allow commercial production for those resources where little or no test drilling has occurred.

For the 22 California resource areas, the total estimated most-likely generation capacity was calculated to be approximately 4,732 MW. The total generation capacity, minus the installed gross capacity of existing generation, was 2,862 MW. Table 1 reflects the estimated generation capacity for each resource area, grouped by geographical area and county.

Table 1: Most-Likely Geothermal Resource Capacity

Geothermal Resource Area	County	MLK MW	Existing Gross MW	MLK-Existing MW
Brawley (North, East South)	Imperial	326	0	326
Dunes	Imperial	11	0	11
East Mesa	Imperial	148	73.2	74.8
Glamis	Imperial	6.4	0	6.4
Heber	Imperial	142	100	42
Mount Signal	Imperial	19	0	19
Niland	Imperial	76	0	76
Salton Sea (including Westmoreland)	Imperial	1750	350	1400
Superstition Mountain	Imperial	9.5	0	9.5
	Imperial Total:	2487.9	523.2	1964.7
Coso Hot Springs	Inyo	355	300	55
Sulfur Bank Field, Clear Lake Area	Lake	43	0	43
Geysers [Lake & Sonoma Counties]	Sonoma	1400	1000	400
Calistoga	Napa	25	0	25
	The Geysers Total:	1468	1000	468
Honey Lake (Wendel-Amedee)	Lassen	8.3	6.4	1.9
Lake City/ Surprise Valley	Modoc	37	0	37
Long Valley (mono- Long Valley) Mammoth Pacific Plants	Mono	111	40	71
Randsburg	San Bernardino/ Kern	48	0	48
Medicine Lake – Fieldwide	Siskiyou	304	0	304
Sespe Hot Springs	Ventura	5.3	0	5.3
Total: Source: California Energy Commission Geothermal Resource Staff Paper		**4825**	**1870**	**2955**

Despite the steam production decline mentioned earlier, The Geyser still potentially has 400 MW of most-likely generation capacity available. The total proven reservoir at The Geysers is nearly 40 square miles, as determined by the extensive shallow and deep drilling in the region. For this area there is a portion of approximately 10 square miles that has never been developed for continuous steam supply. Lying between the Aidlin project area to the northwest and the areas of units 5-6, 7-8 and 11 to the southeast, these 10 square miles comprise about 25 percent of the 40 square-mile total proven area. In addition, about 2 square miles in the northeastern part of the field (within the proven reservoir area) remain untapped at the former Bottle Rock project and the contiguous area to the southeast. In these areas a reasonable estimate of average installed capacity is 33 MW per square mile. The unutilized 12 square miles should therefore be able to support about 400 MW under the right economic conditions.

California has the potential to produce an additional capacity from liquid-dominated resources such as Coso Hot Springs, Imperial Valley, Glass Mountain and Mono/Long Valley. Imperial County has 11 Known Geothermal Resource Areas (KGRA) including Brawley, Salton Sea, and East Mesa, and has the largest potential resource base within the state at about 2,488MW (see Table 2). Sonoma County also has a large resource base estimated at 1,400MW.

Table 2: California Geothermal Potential[5]

County	Technical Potential (MW)	%
Imperial	2,488	52%
Inyo	355	8%
Lake	43	1%
Lassen	8	0%
Modoc	37	1%
Mono	111	2%
Napa	25	1%
San Bernardino/Kern	48	1%
Siskiyou	304	4%
Sonoma	1400	30%
Ventura	5	0%
TOTAL	4,825	

Source: California Energy Commission Geothermal Resource Staff Paper

Electricity Generation-Performance Characteristic and Cost

California's geothermal power production is a mature technology with statewide installed generating capacity of 1,870 MW gross. The gross technical potential for further development in these geothermal resource areas is about 4,732 MW.

The three basic types of geothermal power generation technologies in California are ***dry steam, dual flashed-steam and binary cycles*** with existing gross installed capacities of 1,000 MW, 700 MW, and 170 MW, respectively. Each technology of choice has very distinct characteristics which impose certain limitations on its use and, therefore, affects, its present level of development. Depending on the type of resource, these limitations are related to either the electrical generation systems or the technology to develop the resource itself. Figure 1 shows the known geothermal areas in California.

Performance Characteristics

Geothermal resource characteristics define power generation technology. A dry steam field like the Geysers allows for direct extraction of high-quality steam into a turbine. While this combination of resource and technology is efficient, the absence of other comparable geothermal resources limits applicability of the technology.
Flash steam power plants are the most common. Flash steam plants use geothermal reservoirs of water with temperatures greater than 360°F. Hot water flows up through wells, generally as a result of “stimulation” to the reservoir. As hot water flows upward, the pressure decreases and some of the hot water vaporizes (“flashes”) into steam, generally in a large vessel or flash tank. The high and low-pressure steam is subsequently separated and sent to an appropriate inlet of a turbine. Leftover water and condensed steam are injected back into the reservoir or used in the cooling cycle.
Binary-cycle power plants operate on water at lower temperatures of about 190°–360°F. These plants use heat from the hot water to boil a working fluid, usually an organic compound with a low boiling point. The working fluid is vaporized in a heat exchanger and used to turn a turbine. The water is then injected back into the ground to be reheated. The water and the working fluid are kept separated during the process so there are little or no air emissions.

Figure 1: Known Geothermal Resource Areas

Source: California Energy Commission

Table 3 provides an overview of current (2003) technology characteristics for binary and flash power plants. The technologies are mature with incremental R&D efforts, plant performance is high with availability and capacity factors higher than 90 percent, annual maintenance costs are low, considerable energy is generated with a relatively small footprint, air emissions are either low or non-existent, and most other environmental aspects are positive. Furthermore, economic performance characteristics allow existing geothermal facilities to provide base load generation, albeit in relatively small increments.

Table 3: Summary Technical Performance Characteristics for Geothermal Power Plants, 2003

Technology Characteristics	Flash Cycle	Binary Cycle
Development Status		
Development Status		x
Demonstration	x	x
Performance		
Rated full Load Net Capacity (MWe)	50	50
Power Plant Net Effectiveness (Wh/kg fluid)	27.5	N/A
Electric efficiency (%)	N/A	N/A
Expected Availibility (%)	>99%	>99%
Capacity Factor (%)	85%	85%
Operation		
Operator	Yes	Yes
Dispatchable	Yes	Yes
Load Duty (base, intermediate, peak, intermittent, renewable)	B	Binary Cycle
Maintenance		
Cold Start Up Time (minutes)	hours	hours
Annual Maintenance (hr/yr)	240	
Time Before Intervention (oper. Hrs)	25,000	25,000
Typical Forced Outage Rate (%)	0.60%	0.60%
Sighting / Environmental		
Power Plant Size		
Footpring (ft/kW)	26	26
Infrastructure Needs		
Water Service	Yes	Yes
Waste Water Service	Yes	Yes
Fuel Delivery	No	No
Air Emissions (lb/mWh)		
CO	0.058	0
Nox	0.191	0
SO2	0.026	0
VOC	0.011	0
H2S	0.092	0
Other		
Noise (db @ 1/2 mile)	<65	<65
Water Consumption (acre-feet/yr)	25,000	25,000
Hazardous Materials (trace)	As, Hg, Pb, Sb, B	As, Hg, Pb, Sb, B
Other Hazards Source: California Energy Commission staff with assistance from McNeil Technologies under contract 500-00-031.		

Cost

The technical opportunity for expansion of geothermal capacity in the state is about 2,955 MW (4,732 MW gross minus the gross capacity of existing generation). Economics commands whether new geothermal power plants can be installed cost competitively in California, within the 2005 to 2017 timeframe. An economic analysis calculated the levelized cost of electricity (LCOE) for all technologies using the economic methodology described in this report. Table 4 and 5 depict the summary of the economic analysis performed for all technologies, site-specific to each known geothermal resource areas in constant and current dollars, respectively. All economic analysis that was performed excludes transmission cost and includes a 16 percent return on equity at a 33 percent equity ratio.

The base case (as-in service year 2005) levelized cost of electricity (LCOE) for an installation of new dry steam plant is $0.0691/kWh with production tax credit (PTC) and $0.0781/kWh without PTC.

For dual flashed-steam systems, the base case (as-in service year 2005) LCOE's with PTC ranges from $0.0473/kWh to $0.889/kWh and LCOE's without PTC range from $0.0563/kWh to $0.0979/kWh.

The LCOE's for the installation of new binary cycles (as-in service year 2005) with PTC range from $0.040/kWh to $0.0931/kWh and the LCOE's without PTC range from $0.049/kWh to $0.1021/kWh.

Table 4: Summary of Geothermal – Levelized Cost of Electricity (2004 constant $/kWh).

Technology	Dry Steam													
		Capital Cost ($/kW)	LCOE (2004 Constant $/kWh)											
Year	Potential Develop-	2005	Transmission		No Transmission		Transmission		No Transmission		Transmission		No Transmission	
Geothermal	ment (MW)	Base Case	PTC	No PTC	PTC	No PTC	PTC	No PTC	PTC	No PTC	PTC	No PTC	PTC	No PTC
Geysers	400	3,725	0.0693	0.0783	0.0691	0.0781	0.0660	0.0750	0.0658	0.0748	0.0628	0.0717	0.0626	0.0716

Technology	Dual Flash													
		Capital Cost ($/kW)	LCOE (2004 Constant $/kWh)											
	Potential		2005				2010				2017			
Year	Develop-	2005	Transmission		No Transmission		Transmission		No Transmission		Transmission		No Transmission	
Geothermal	ment (MW)	Base Case	PTC	No PTC	PTC	No PTC	PTC	No PTC	PTC	No PTC	PTC	No PTC	PTC	No PTC
Calistoga	25	3,403	0.0703	0.0793	0.0691	0.0781	0.0662	0.0752	0.0658	0.0748	0.0615	0.0705	0.0626	0.0716
Brawley (North)	135	2,638	0.0620	0.0709	0.0542	0.0631	0.0573	0.0663	0.0496	0.0586	0.0521	0.0611	0.0446	0.0536
Brawley (East)	129	4,195	0.0898	0.0988	0.0817	0.0907	0.0835	0.0925	0.0754	0.0844	0.0764	0.0854	0.0685	0.0775
Brawley (South)	62	4,606	0.1059	0.1149	0.0889	0.0979	0.0990	0.1080	0.0823	0.0912	0.0912	0.1002	0.0748	0.0838
Coso	55	3,405	0.0689	0.0779	0.0677	0.0767	0.0635	0.0725	0.0623	0.0713	0.0575	0.0665	0.0564	0.0654
Lake City / Surprise Valley	37	3,146	0.0651	0.0740	0.0631	0.0721	0.0599	0.0689	0.058	0.067	0.0542	0.0632	0.0524	0.0614
Medicine Lake (Fourmile Hill)	36	2,674	0.1383	0.1473	0.0548	0.0638	0.1328	0.1418	0.0502	0.0592	0.1259	0.1349	0.0452	0.0541
Medicine Lake (Telephon e Flat)	175	2,275	0.0649	0.0739	0.0477	0.0567	0.0606	0.0696	0.0436	0.0526	0.0556	0.0646	0.039	0.048
Niland	76	3,249	0.0659	0.0749	0.065	0.0739	0.0607	0.0697	0.0598	0.0687	0.0549	0.0639	0.054	0.063
Randsburg	48	2,615	0.0571	0.0661	0.0538	0.0627	0.0525	0.0615	0.0492	0.0582	0.0475	0.0565	0.0442	0.0532
Salton Sea (Low)	1400	2,250	0.0502	0.0592	0.0473	0.0563	0.0461	0.0551	0.0432	0.0522	0.0415	0.0505	0.0386	0.0476
Salton Sea (High)	1400	4,500	0.0900	0.0990	0.0871	0.0961	0.0834	0.0924	0.0805	0.0895	0.0760	0.0850	0.0732	0.0822
Sulphur Bank	43	2,347	0.0507	0.0596	0.049	0.058	0.0464	0.0554	0.0448	0.0538	0.0417	0.0507	0.0401	0.0491
Range		2,250			0.0473	0.0563			0.0432	0.0522			0.0386	0.0476
Range		4,606			0.0889	0.0979			0.0823	0.0912			0.0748	0.0838
Average		3,177			0.0638	0.0728			0.0588	0.0678			0.0534	0.0623

Technology	Binary													
		Capital Cost ($/kW)	LCOE (2004 Constant $/kWh)											
	Potential		2005				2010				2017			
Year	Develop-	2005	Transmission		No Transmission		Transmission		No Transmission		Transmission		No Transmission	
Geothermal	ment (MW)	Base Case	PTC	No PTC	PTC	No PTC	PTC	NO PTC	PTC	No PTC	PTC	NO PTC	PTC	No PTC
Long Valley - M-P Leases	71	2,034	0.0480	0.0570	0.04	0.049	0.0437	0.0527	0.0358	0.0448	0.0402	0.0492	0.0324	0.0414
Honey Lake	1.9	2,684	0.0871	0.0961	0.0511	0.0601	0.0796	0.0886	0.0444	0.0534	0.0712	0.0802	0.0363	0.0453
Dunes	11	4,085	0.0813	0.0903	0.0751	0.0841	0.0718	0.0808	0.0657	0.0747	0.0602	0.0692	0.0542	0.0632
East Mesa	74.8	5,141	0.0941	0.1030	0.0931	0.1021	0.0827	0.0917	0.0818	0.0908	0.0686	0.0775	0.0677	0.0767
Glamis	6.4	4,953	0.1327	0.1417	0.0899	0.0989	0.1208	0.1298	0.079	0.0879	0.1067	0.1157	0.0653	0.0743
Heber	42	2,706	0.0531	0.0621	0.0515	0.0605	0.0463	0.0553	0.0447	0.0537	0.0382	0.0472	0.0366	0.0456
Mount Signal	19	2,746	0.0594	0.0684	0.0522	0.0612	0.0524	0.0614	0.0453	0.0543	0.0441	0.0531	0.0371	0.0461
Sespe Hot Springs	5.3	4,112	0.0885	0.0975	0.0755	0.0845	0.0789	0.0879	0.0661	0.0751	0.0671	0.0761	0.0545	0.0635
Superstitio n Mountain	9.5	3,211	0.0635	0.0725	0.0601	0.0691	0.0557	0.0647	0.0524	0.0614	0.0463	0.0553	0.0431	0.0521
Range		2,034			0.04	0.049			0.0358	0.0448			0.0324	0.0414
Range		5,141			0.0931	0.1021			0.0818	0.0908			0.0677	0.0767

Source: California Energy Commission staff with assistance from McNeil Technologies under contract 500-00-031.

Table 5: Summary of Geothermal – Levelized Cost of Electricity (2004 current $/kWh).

Technology	Dry Steam													
	Potential Develop- ment (MW)	Capital Cost ($/kW)	**LCOE** (2004 Current $/kWh)											
Year		2005	Transmission		No Transmission		Transmission		No Transmission		Transmission		No Transmission	
Geothermal		Base Case	PTC	No PTC	PTC	No PTC	PTC	No PTC	PTC	No PTC	PTC	No PTC	PTC	No PTC
Geysers	400	3,725	0.0856	0.0967	0.0854	0.0965	0.0816	0.0927	0.0814	0.0925	0.0776	0.0887	0.0774	0.0885

Technology	Dual Flash													
	Potential Develop- ment (MW)	Capital Cost ($/kW)	**LCOE** (2004 Current $/kWh)											
			2005				2010				2017			
Year		2005	Transmission		No Transmission		Transmission		No Transmission		Transmission		No Transmission	
Geothermal		Base Case	PTC	No PTC	PTC	No PTC	PTC	No PTC	PTC	No PTC	PTC	No PTC	PTC	No PTC
Calistoga	25	3,403	0.0869	0.0980	0.0836	0.0948	0.0819	0.0930	0.0786	0.0897	0.0760	0.0871	0.0728	0.0839
Brawley (North)	135	2,638	0.0766	0.0877	0.0669	0.0780	0.0708	0.0820	0.0613	0.0724	0.0644	0.0755	0.0551	0.0662
Brawley (East)	129	4,195	0.1110	0.1221	0.1009	0.1121	0.1032	0.1143	0.0932	0.1043	0.0944	0.1055	0.0847	0.0958
Brawley (South)	62	4,606	0.1309	0.1420	0.1099	0.1210	0.1224	0.1335	0.1017	0.1128	0.1127	0.1239	0.0925	0.1036
Coso	55	3,405	0.0852	0.0963	0.0837	0.0948	0.0785	0.0896	0.0770	0.0881	0.0711	0.0822	0.0697	0.0808
Lake City / Surprise Valley	37	3,146	0.0804	0.0915	0.0780	0.0891	0.0741	0.0852	0.0717	0.0828	0.0670	0.0782	0.0648	0.0759
Medicine Lake (Fourmile Hill)	36	2,674	0.1709	0.1820	0.0677	0.0788	0.1641	0.1752	0.0621	0.0732	0.1556	0.1667	0.0558	0.0669
Medicine Lake (Telephon e Flat)	175	2,275	0.0802	0.0913	0.0590	0.0701	0.0749	0.0860	0.0539	0.0650	0.0688	0.0799	0.0482	0.0593
Niland	76	3,249	0.0814	0.0925	0.0803	0.0914	0.0750	0.0861	0.0738	0.0850	0.0678	0.0789	0.0667	0.0778
Randsburg	48	2,615	0.0706	0.0817	0.0664	0.0775	0.0649	0.0760	0.0608	0.0720	0.0587	0.0698	0.0547	0.0658
Salton Sea (Low)	1400	2,250	0.0621	0.0732	0.0585	0.0696	0.0570	0.0681	0.0534	0.0645	0.0513	0.0624	0.0478	0.0589
Salton Sea (High)	1400	4,500	0.1112	0.1224	0.1076	0.1187	0.1031	0.1142	0.0995	0.1106	0.0940	0.1051	0.0904	0.1016
Sulphur Bank	43	2,347	0.0626	0.0737	0.0606	0.0717	0.0574	0.0685	0.0554	0.0665	0.0516	0.0627	0.0496	0.0607
Range		2,250			0.0473	0.0563			0.0432	0.0522			0.0386	0.0476
Range		4,606			0.0889	0.0979			0.0823	0.0912			0.0748	0.0838
Average		3,177			0.0638	0.0728			0.0588	0.0678			0.0534	0.0623

Technology	Binary													
	Potential Develop- ment (MW)	Capital Cost ($/kW)	**LCOE** (2004 Current $/kWh)											
			2005				2010				2017			
Year		2005	Transmission		No Transmission		Transmission		No Transmission		Transmission		No Transmission	
Geothermal		Base Case	PTC	No PTC	PTC	No PTC	PTC	NO PTC	PTC	No PTC	PTC	NO PTC	PTC	No PTC
Long Valley - M-P Leases	71	2,034	0.0594	0.0705	0.0494	0.0605	0.0540	0.0651	0.0443	0.0554	0.0496	0.0608	0.0400	0.0511
Honey Lake	1.9	2,684	0.1077	0.1188	0.0632	0.0743	0.0984	0.1095	0.0549	0.0660	0.0880	0.0991	0.0449	0.0560
Dunes	11	4,085	0.1005	0.1116	0.0928	0.1039	0.0888	0.0999	0.0812	0.0924	0.0744	0.0855	0.0670	0.0781
East Mesa	74.8	5,141	0.1162	0.1274	0.1151	0.1262	0.1022	0.1133	0.1011	0.1122	0.0847	0.0958	0.0836	0.0947
Glamis	6.4	4,953	0.1640	0.1751	0.1111	0.1222	0.1493	0.1604	0.0976	0.1087	0.1319	0.1430	0.0807	0.0918
Heber	42	2,706	0.0657	0.0768	0.0636	0.0747	0.0572	0.0684	0.0553	0.0664	0.0472	0.0583	0.0453	0.0564
Mount Signal	19	2,746	0.0734	0.0845	0.0645	0.0756	0.0647	0.0759	0.0560	0.0671	0.0545	0.0656	0.0459	0.0570
Sespe Hot Springs	5.3	4,112	0.1094	0.1205	0.0934	0.1045	0.0975	0.1086	0.0818	0.0929	0.0830	0.0941	0.0674	0.0785
Superstitio n Mountain	9.5	3,211	0.0785	0.0896	0.0743	0.0854	0.0689	0.0800	0.0648	0.0759	0.0573	0.0684	0.0532	0.0643
Range		2,034			0.04	0.049			0.0358	0.0448			0.0324	0.0414
Range		5,141			0.0931	0.1021			0.0818	0.0908			0.0677	0.0767

Source: California Energy Commission staff with assistance from McNeil Technologies under contract 500-00-031.

Dry Steam – Results of Economic Analysis

An economic analysis calculated the levelized cost of electricity LCOE for dry steam as-in service years of 2005, 2010, and 2017 using the economic methodology described in this report. The cost analysis is estimated at 2004 dollars and is site-specific to The Geysers area. The simplified model calculates both the current dollars and constant dollars levelized cost of electricity for dry steam geothermal plant.

Assumptions

The LCOE used in the paper are assumed to be from a project/owner developer perspective. The dry-steam geothermal resource supply and the electricity generation systems are integrated, physically connected, and base loaded in application. Table 6 shows the estimated capital costs, operation and maintenance (O&M) costs and capacity factors. Table 7 shows the other inputs and parameters used in the model.

For as-in service in 2005, the assumed capital cost is $3,725/kW. The size of the dry steam plant is assumed at 50 MWnet. The capital cost breakdown includes zero exploration cost, $765/kW confirmation cost, and $2,960/kW site development cost. Site development cost includes drilling costs for production and injection wells, and the cost of the power plant and gathering system. Details of exploration, confirmation and development costs can be found at http://www.energy.ca.gov/reports/500-04-051.PDF. Capacity factor is assumed at 95 percent and 4 percent per year decrease in well productivity. Fixed O&M Cost of $82.6/kW-yr (57 percent of this O&M cost from power plant, 33 percent for field, general O&M rework, 8 percent for make-up wells, and 2 percent for injection wells). Other variable O&M expense is assumed to be at 5 percent of fixed O&M cost. Royalty cost is assumed at 3 percent of revenue of the sale of electricity. Wholesale price of electricity was assumed at $.0429/kWh. Accelerated depreciation (MACRS – 5 yr property) and additional 30 percent depreciation and 10 percent investment tax credit were assumed. Federal tax and state tax rates were assumed at 34 percent and 6.65 percent, respectively. Property tax rate (and also insurance) is assumed to be 1 percent of the book value. Financing assumed 2:1 or 67 percent debt ratio, 8.4 percent interest rate on debt, 16 percent cost of equity, and 20 years economic life. General inflation and escalation rates for O&M and other expenses are assumed at 2.8 percent. Production tax credit (PTC) is available for this project, at least 5 years at $.018/kWh[6]. Capacity payments are provided under some contracts by utilities or generators who can guarantee their facilities will operate with high reliability during the year, especially during times of peak electricity demand. In the calculation of LCOE, capacity payments were assumed to be zero.

The projected capital costs and O&M costs for as-in service years of 2010 and 2017 are shown in Table 6. Capacity factors were assumed to be 95 percent and all other estimates remain the same as in 2005. Levelized costs of dry steam plants were calculated with and without PTC and no transmission costs.

Table 6: Capital and Operating & Maintenance costs and capacity factors assumptions for dry steam technology (2004 constant $/kWh).

Technology	Dry Stream		
Year	**2005**	**2010**	**2017**
Installed Capital Costs ($/kW)			
Exploration Costs			
Confirmation Costs	765	743	720
Site Development Costs	2960	2874	2787
Total Capital Cost	**3,725**	**3,617**	**3,507**
Operation and Maintenance Costs ($/kW-yr)			
Field, General O&M & Rework	27.8	25.0	22.3
Makeup Wells	10.5	9.4	8.4
Relocate Injection Wells	2.3	2.1	1.9
Power Plant O&M	42.0	37.9	33.7
Total Operating Costs	**83**	**74**	**66**
Capacity Factors (%)	**95**	**95**	**95**

Sources: For capital costs see http://www.energy.ca.gov/reports/500-04-051.PDF (New Geothermal Site Identification and Qualification). For O&M costs see Capacity and Ownership: CAISO, Generation Facilities Summary 2003-2004 and Navigant assumptions at http://www.energy.ca.gov/reports/2003-11-24_500-03-080F.PDF

Table 7: Economic model base case assumptions for dry steam Year online: 2005, no Production Tax Credit (PTC)

CAPITAL COSTS and PERFORMANCE	
Capital Cost ($/kW)	**3,725**
Net Plant Capacity (kW)	**50,000**
Availability/Capacity Factor	**95%**
Annual Decrease In Well Productivity	**4%**
Total Transmission Cost	-
Annual Production (kWh)	416,100,100
Annual Hours	8,322
EXPENSES	
Electricity Sales Price (For Royalty Calculation) ($/Kwh)	**0.043**
Royalty Rate (% of revenue)	**4%**
Operations and Maintenance ($/kW-yr.)	**82.6**
Variable Cost (% Of Fixed Cost)	**5.0**
TAXES	
Federal Tax Rate (%)	**34.00**
State Tax Rate (%)	**6.65**
Combined Tax Rate (%)	38.39
Investment Tax Credit (%)	10%
Production Tax Credit (0.018 $/kWh) five years)	$ 0.0
Property Tax Rate (%)	1%
INCOME (other than energy)	
Capacity Payment ($/kW-y)	**0**
Interest Rate on Debt Reserve (%)	**7.00**

ESCALATION/INFLATION	
General Inflation (%)	**2.80**
Escalation--Fuel (%)	**0.00**
Escalation--Other (%)	**2.80**
FINANCE	
Debt Ratio (%)	**67.00**
Equity Ratio (%)	33.00
Interest Rate On Debt (%)	**8.40**
Life Of Loan (Y)	**20**
Cost Of Equity (%)	**16.00**
Cost of Money (%)	10.91
Total Cost of Plant ($)	186,250,000
Total Equity Cost ($)	61,462,500
Total Debt Cost ($)	124,787,500
Capital Recovery Factor (Equity)	0.1687
Capital Recovery Factor (Debt)	0.1049
Annual Equity Recovery ($/y)	10,366,697
Annual Debt Payment ($/y)	13,090,535
Debt Reserve ($)	13,090,535
Annual Debt Reserve Interest ($/y)	916,337
Annual Capacity Payment ($/y)	0
Loan Origination Fee (one time)	1%
ACRS DEPRECIATION (5 yr property)	
Year 1	**0.2000**
Year 2	**0.3200**
Year 3	**0.1920**
Year 4	**0.1152**
Year 5	**0.1152**
Year 6	**0.0576**
Total	1.0000
Additional depreciation (%)	30%

Dual Flash - Results of Economic Analysis

Using the economic methodology described in this report, LCOE's were calculated for dual flashed-steam for site specific geothermal resource areas such as Brawley (north, east and south), Niland, Salton Sea, Coso, Sulfur Bank field, Clear Lake, Calistoga, Lake City, Surprise Valley, Randsburg, and Medicine Lake. The cost analysis was estimated at 2004$. The simplified model calculates both current dollars and constant dollar LCOE's.

Assumptions

The LCOE presented here are assumed to be from a project/owner developer perspective. The dual flashed-steam geothermal resource supply and the electricity generation systems are integrated and physically connected and are base load application. Table 8 shows estimated capital costs, operation and maintenance (O&M) costs and capacity factors for dual-flash for as-in service years 2005, 2010 and 2017.

The size of the dual flashed steam is assumed at a module of 50 MWnet or whatever is available in a given resource. As shown in Table 8, capital cost breakdown includes exploration cost, confirmation cost, and site development cost. Site development cost includes drilling costs for production and injection wells, and cost of the power plant and gathering system. Details of the exploration, confirmation and development costs can be found at http://www.energy.ca.gov/reports/500-04-051.PDF. Capacity factors were assumed at 90 percent, 91 percent, and 93 percent for as-in service years of 2005, 2010 and 2017, respectively. Four percent per year decrease was assumed in well productivity. Fixed O&M costs (57 percent of this O&M cost from power plant, 33 percent for field, general O&M rework, 8 percent for make-up wells, and 2 percent for injection wells) were assumed at $82.6/kW-yr, $74.4/kW-yr, and $66.3/kW-yr for 2005, 2010, and 2017. Variable O&M expense is assumed to be at 5 percent of fixed O&M cost. Royalty cost is assumed at 3 percent of revenue of the sale of electricity. Average wholesale price of electricity was assumed at $.0429/kWh. Accelerated depreciation (MACRS – 5 yr property) and additional 30 percent depreciation and 10percent investment tax credit were assumed. Federal tax rate and state tax rate were assumed at 34 percent and 6.65 percent, respectively. Property tax rate (and also insurance) is assumed to be 1 percent of the book value. Financing assumed 2:1 or 67 percent debt ratio, 8.4 percent interest rate on debt, 16 percent cost of equity, and 20 years economic life. General inflation and escalation rates for O&M and other expenses were assumed at 2.8 percent. Production tax credit (PTC) is available for this project, at least 5 years at $.018/kWh[7]. Capacity payments are provided under some contracts by utilities or generators who can guarantee their facilities will operate with high reliability during the year, especially during times of peak electricity demand. In the calculation of LCOE, capacity payments were assumed to be zero. Levelized costs of dual flash steam plants were calculated with and without PTC and no transmission costs.

Table 8: Capital cost, O&M cost, capacity factors for dual flash (2004$)

Technology	Flash												
Field/Area	**Calistoga**	**Brawley**	**Braw-ley**	**Brawley**	**Coso**	**Lake City / Surprise Valley**	**Med. Lake**	**Med. Lake**	**Niland**	**Rands-burg**	**Salton Sea**	**Salton Sea**	**Sul-phur Bank**
Area/Power Plant	Calistoga	Brawley (North Brawley)	East Brawley	South Brawley (Mesquite field)	Field-wide Summary	Lake City	Fourmile Hill	Telephone Flat	Niland	Randsburg	Field-wide summary	Field-wide summary	Clear Lake
Potential Development (MW)	**25**	**135**	**129**	**62**	**55**	**37**	**36**	**175**	**76**	**48**	**1400**	**1400**	**43**
Year	**2005**												
Installed Capital Costs ($/kW)													
Exploration Costs			1	1						9			
Confirmation Costs	375	107	596	662	541	287	292	139	385	244	130		208
Site Development Costs	3,028	2,531	3,598	3,943	2,864	2,859	2,382	2,136	2,864	2,362	2,120		2,139
Total Capital Cost	**3,403**	**2,638**	**4,195**	**4,606**	**3,405**	**3,146**	**2,674**	**2,275**	**3,249**	**2,615**	**2,250**	**4,500**	**2,347**
Operation and Maintenance Cost ($/kW-yr)													
Field, General O&M and Rework	27	27	27	27	27	27	27	27	27	27	27	27	27
Makeup Wells	7	7	7	7	7	7	7	7	7	7	7	7	7
Relocation Injection Wells	2	2	2	2	2	2	2	2	2	2	2	2	2
Power Plant O&M	47	47	47	47	47	47	47	47	47	47	47	47	47
Total Operating Costs	**83**	**83**	**83**	**83**	**83**	**83**	**83**	**83**	**83**	**83**	**83**	**83**	**83**
Capacity Factor (%)	**90**	**90**	**90**	**90**	**90**	**90**	**90**	**90**	**90**	**90**	**90**	**90**	**90**

Technology	Flash												
Field/Area	**Calistoga**	**Brawley**	**Braw-ley**	**Brawley**	**Coso**	**Lake City / Surprise Valley**	**Med. Lake**	**Med. Lake**	**Niland**	**Rands-burg**	**Salton Sea**	**Salton Sea**	**Sul-phur Bank**
Area/Power Plant	Calistoga	Brawley (North Brawley)	East Brawley	South Brawley (Mesquite field)	Field-wide Summary	Lake City	Fourmile Hill	Telephone Flat	Niland	Randsburg	Field-wide summary	Field-wide summary	Clear Lake
Potential Development (MW)	**25**	**135**	**129**	**62**	**55**	**37**	**36**	**175**	**76**	**48**	**1400**	**1400**	**43**
Year	**2010**												
Installed Capital Costs ($/kW)													
Exploration Costs	0	0	1	1	0	0	0	0	0	9	0	0	0
Confirmation Costs	364	102	565	628	513	272	277	132	365	231	123	0	197
Site Development Costs	2,940	2,401	3,413	3,741	2,717	2,712	2,260	2,026	2,717	2,241	2,011	0	2,029
Total Capital Cost	**3,304**	**2,503**	**3,980**	**4,370**	**3,230**	**2,985**	**2,537**	**2,158**	**3,082**	**2,481**	**2,135**	**4,269**	**2,227**
Operation and Maintenance Cost ($/kW-yr)													
Field, General O&M and Rework	24	24	24	24	24	24	24	24	24	24	24	24	24
Makeup Wells	6	6	6	6	6	6	6	6	6	6	6	6	6
Relocation Injection Wells	2	2	2	2	2	2	2	2	2	2	2	2	2
Power Plant O&M	42	42	42	42	42	42	42	42	42	42	42	42	42
Total Operating Costs	**74**	**74**	**74**	**74**	**74**	**74**	**74**	**74**	**74**	**74**	**74**	**74**	**74**
Capacity Factor (%)	**91**	**91**	**91**	**91**	**91**	**91**	**91**	**91**	**91**	**91**	**91**	**91**	**91**

Technology	Flash												
Field/Area	**Calistoga**	**Brawley**	**Braw-ley**	**Brawley**	**Coso**	**Lake City / Surprise Valley**	**Med. Lake**	**Med. Lake**	**Niland**	**Rands-burg**	**Salton Sea**	**Salton Sea**	**Sul-phur Bank**
Area/Power Plant	Calistoga	Brawley (North Brawley)	East Brawley	South Brawley (Mesquite field)	Field-wide Summary	Lake City	Fourmile Hill	Telephone Flat	Niland	Randsburg	Field-wide summary	Field-wide summary	Clear Lake
Potential Development (MW)	**25**	**135**	**129**	**62**	**55**	**37**	**36**	**175**	**76**	**48**	**1400**	**1400**	**43**
Year	**2017**												
Installed Capital Costs ($/kW)													
Exploration Costs	0	0	1	1	0	0	0	0	0	8	0	0	0
Confirmation Costs	353	96	535	594	486	258	262	125	346	219	117	0	187
Site Development Costs	2,851	2,271	3,229	3,539	2,570	2,566	2,138	1,917	2,570	2,120	1,903	0	1,920
Total Capital Cost	**3,204**	**2,367**	**3,765**	**4,134**	**3,056**	**2,823**	**2,400**	**2,042**	**2,916**	**2,347**	**2,019**	**4,038**	**2,106**
Operation and Maintenance Cost ($/kW-yr)													
Field, General O&M and Rework	22	22	22	22	22	22	22	22	22	22	22	22	22
Makeup Wells	6	6	6	6	6	6	6	6	6	6	6	6	6
Relocation Injection Wells	1	1	1	1	1	1	1	1	1	1	1	1	1
Power Plant O&M	38	38	38	38	38	38	38	38	38	38	38	38	38
Total Operating Costs	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**	**66**
Capacity Factor (%)	**93**	**93**	**93**	**93**	**93**	**93**	**93**	**93**	**93**	**93**	**93**	**93**	**93**

Source: California Energy Commission staff with assistance from McNeil Technologies under contract 500-00-031.

Binary – Results of Economic Analysis

LCOE's were calculated for binary cycle power plants for site specific geothermal resource areas such as Dunes, East Mesa, Glamis, Heber, Mount Signal, Superstition Mountain, Honey Lake, Long Valley, and Sespe Hot Springs. The cost analysis was estimated at 2004 dollars. The simplified model calculates both the current dollars and constant dollars LCOE's.

Assumptions

The LCOE presented here are assumed to be from a project/owner developer perspective.
The binary power plants, geothermal resource supply, and the electricity generation systems are integrated and physically connected. Typically, binary plants operate as base load power. Table 9 shows the estimated capital costs, operation and maintenance (O&M) costs and capacity factors for dual-flash for as-in service years 2005, 2010 and 2017.

The potential MW of the binary cycles for different resource areas are also shown in Table 9. As shown in Table 9, capital cost breakdown includes exploration, confirmation, and site development costs. Site development cost includes drilling costs for production and injection wells, and the cost of power plant and gathering systems. Details of these estimated costs can also be found at http://www.energy.ca.gov/reports/500-04-051.PDF. Capacity factors were assumed at 93 percent, 95 percent, and 96 percent for as-in service years of 2005, 2010 and 2017, respectively. Four percent per year decrease was assumed in well productivity in all sites. Fixed O&M costs (57 percent of this O&M cost from power plant, 33 percent for field, general O&M rework, 8 percent for make-up wells, and 2 percent for injection wells) were assumed at $72/kW-yr, $64/kW-yr, and $57/kW-yr for 2005, 2010, and 2017, respectively. Variable O&M expense was assumed to be at 5 percent of fixed O&M cost. Royalty cost was assumed at 3 percent of revenue of the sale of electricity. Wholesale price of electricity was assumed at $.0429/kWh. Accelerated depreciation (MACRS – 5 yr property) and additional 30 percent depreciation and 10 percent investment tax credit were assumed. Federal tax rate and state tax rate were assumed at 34 percent and 6.65 percent, respectively. Property tax rate (and also insurance) is assumed to be 1 percent of the book value. Financing assumed 2:1 or 67 percent debt ratio, 8.4 percent interest rate on debt, 16 percent cost of equity, and 20 years economic life. General inflation and escalation rates for O&M and other expenses were assumed at 2.8 percent. Production tax credit (PTC) is available for this project, at least 5 years at $.018/kWh[8]. No capacity payments were assumed in the calculation. Levelized costs of binary plants were calculated with and without PTC and exclude transmission costs.

Table 9: Capital cost, O&M cost, capacity factors for binary cycle (2004 dollars)

Technology	Binary								
Field/Area	Long Valley - M-P Leases	Honey Lake	Dunes	East Mesa	Glamis	Heber	Mount Signal	Sespe Hot Springs	Superstition Mountain
Area/Power Plant	M-P Lease Summary	Area-wide Summary	Dunes	Field-wide summary	Glamis	Field-wide Summary	Mount Signal	Sespe Hot Springs	Superstition Mountain
Potential Development (MW)	**71**	**1.9**	**11**	**74.8**	**6.4**	**42**	**19**	**5.3**	**9.5**
Year	**2005**								
Installed Capital Costs ($/kw)									
Exploration Costs	35		76		142		23	178	89
Confirmation Costs	124	458	585	734	656	222	242	493	539
Site Development Costs	1,875	2,226	3,424	4,407	4,155	2,484	2,481	3,441	2,583
Total Capital Cost	**2,034**	**2,684**	**4,085**	**5,141**	**4,953**	**2,706**	**2,746**	**4,112**	**3,211**
Operation and Maintenance Cost ($/kW-yr)									
Field, General O& M and Rework	24	24	24	24	24	24	24	24	24
Makeup Wells	6	6	6	6	6	6	6	6	6
Relocate Injection Wells	1	1	1	1	1	1	1	1	1
Power Plant O&M	41	41	41	41	41	41	41	41	41
Total Operating Costs	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**	**72**
Capacity Factor (%)	**93**	**93**	**93**	**93**	**93**	**93**	**93**	**93**	**93**

Technology	Binary								
Field/Area	Long Valley - M-P Leases	Honey Lake	Dunes	East Mesa	Glamis	Heber	Mount Signal	Sespe Hot Springs	Superstition Mountain
Area/Power Plant	M-P Lease Summary	Area-wide Summary	Dunes	Field-wide summary	Glamis	Field-wide Summary	Mount Signal	Sespe Hot Springs	Superstition Mountain
Potential Development (MW)	**71**	**1.9**	**11**	**74.8**	**6.4**	**42**	**19**	**5.3**	**9.5**
Year	**2010**								
Installed Capital Costs ($/kW)									
Exploration Costs	33	0	69	0	129	0	21	162	81
Confirmation Costs	118	417	532	668	597	202	220	449	490
Site Development Costs	1,779	2,025	3,115	4,010	3,781	2,260	2,257	3,131	2,350
Total Capital Cost	**1,930**	**2,442**	**3,717**	**4,678**	**4,507**	**2,462**	**2,499**	**3,741**	**2,922**
Operation and Maintenance Cost ($/kW-yr)									
Field, General O&M and Rework	21	21	21	21	21	21	21	21	21
Makeup Wells	5	5	5	5	5	5	5	5	5
Relocation Injection Wells	1	1	1	1	1	1	1	1	1
Power Plant O&M	37	37	37	37	37	37	37	37	37
Total Operating Costs	**64**	**64**	**64**	**64**	**64**	**64**	**64**	**64**	**64**
Capacity Factor (%)	**95**	**95**	**95**	**95**	**95**	**95**	**95**	**95**	**95**

Technology	Binary								
Field/Area	Long Valley - M-P Leases	Honey Lake	Dunes	East Mesa	Glamis	Heber	Mount Signal	Sespe Hot Springs	Superstition Mountain
Area/Power Plant	M-P Lease Summary	Area-wide Summary	Dunes	Field-wide summary	Glamis	Field-wide Summary	Mount Signal	Sespe Hot Springs	Superstition Mountain
Potential Development (MW)	**71**	**1.9**	**11**	**74.8**	**6.4**	**42**	**19**	**5.3**	**9.5**
Year	**2017**								
Installed Capital Costs ($/kW)									
Exploration Costs	31	0	58	0	109	0	18	137	68
Confirmation Costs	111	352	450	565	505	171	186	379	415
Site Development Costs	1,683	1,712	2,634	3,390	3,196	1,911	1,908	2,647	1,987
Total Capital Cost	**1,825**	**2,065**	**3,142**	**3,955**	**3,810**	**2,082**	**2,112**	**3,163**	**2,470**
Operation and Maintenance Cost ($/kW-yr)									
Field, General O&M and Rework	19	19	19	19	19	19	19	19	19
Makeup Wells	5	5	5	5	5	5	5	5	5
Relocation Injection Wells	1	1	1	1	1	1	1	1	1
Power Plant O&M	33	33	33	33	33	33	33	33	33
Total Operating Costs	**57**	**57**	**57**	**57**	**57**	**57**	**57**	**57**	**57**
Capacity Factor (%)	**96**	**96**	**96**	**96**	**96**	**96**	**96**	**96**	**96**

Source: California Energy Commission staff with assistance from McNeil Technologies under contract 500-00-031.

Conclusion

The technical opportunity for expansion of geothermal capacity is about 2,955 MW. With regard to dry steam resources, development at The Geysers should be planned with more caution. Recent geothermal resource assessment conducted by GeothermEx at The Geysers (Lake and Sonoma Counties) shows that 400 MW can be most likely developed. The total proven reservoir at The Geysers is nearly 40 square miles, as determined by the extensive shallow and deep drilling in the region. For this area, there is a portion of approximately 10 square miles which has never been developed for continuous steam supply. This 10 square miles, lying between the Aidlin project area to the northwest and the areas of units 5-6, 7-8 and 11 to the southeast, comprises about 25 percent of the 40 square miles total proven area. In addition, about 2 square miles in the northeastern of the field (within the proven reservoir area) remain untapped at the former Bottle Rock project and the contiguous area to the southeast. In these areas, a reasonable estimate of average installed capacity is 33 MW per square mile. Therefore, the unutilized 12 square miles should be able to support about 400 MW under the right economic conditions. This will be eight 50-MW dry steam power plants.

GeothermEx's study shows that about 2,178 MW of dual flash systems may be most likely developed in California now and in the future depending on economic conditions. The undeveloped geothermal resource areas with no existing power plants but which have great potential for development using dual-flash system include; 135 MW in North Brawley, 129 MW in East Brawley, 62 MW in South Brawley, 76 MW in Niland, 43 MW in Sulfur Bank field, Clear Lake, 25 MW in Calistoga, 37 MW in Lake City, Surprise Valley, 48 MW in Randsburg, 36 MW in Fourmile Hill, Medicine Lake, and 175 MW in Telephone Flat, Medicine Lake. High likelihood of further development for geothermal resource areas with existing dual flash system includes a potential of 1,400 MW in Salton Sea and 55 MW in Coso.

For binary systems, GeothermEx's study shows that about 284 MW may most likely be developed in California. The technical opportunity for binary cycles development Imperial County is about 163 MW, including: 11 MW in Dunes, 74.8 MW in East Mesa, 6.4 MW in Glamis, 42 MW in Heber, 19 MW in Mount Signal, and 9.5 MW in Superstitions Mountain. Technical opportunities for binary cycles can also be developed at Honey Lake, Lassen County for 1.9 MW, Long Valley, Mono County for 71 MW, and Sespe Hot Springs, Ventura County for 5.3 MW.

Adding New Geothermal Generation to the Grid

As stated in the previous section, economics determine whether new geothermal power plants can be installed cost competitively. The SVA approach includes transmission costs in the economic analysis and a locational value analysis. The locational value analysis evaluates the advantages and disadvantages of new geothermal generation in relation to existing generation, loads and the transmission grid.

In order to evaluate interaction of the various transmission and power plant additions on California's transmission system, a transmission power flow model of the entire state was created. This was developed by the Davis Consultants (DPC) team. This team consisted of Davis Power Consultants, PowerWorld and Anthony Engineering. Briefly, the DPC team collected load flows from PG&E, SCE and SDG&E and merged the datasets. Several problems were encountered. Since each IOU does not consider the inter- and intra-state flows of the other IOUs, determining proper power flows was a problem. Problems also existed with bus numbering and connection point modeling between control areas. Ultimately, these problems were resolved.

DPC's next task was to develop the methodology for the locational value analysis. DPC wanted to develop an approach that could be easily completed and also allowed for comparison of various power plant locations on an even and unbiased basis. The goal was to weight site options by their respective benefits to system reliability.

In running contingency analysis on more than 5,000 transmission lines, transformers and power plants, a contingency outage could cause more than one transmission element to become overloaded at one time. Since an element could be overloaded more than once during the 5,000 contingency outages, a methodology must be developed that recognizes these multiple occurrences and weights their respective impacts to the total reliability of the transmission grid.

DPC developed a factor called the Weighted Transmission Loading Relief Factor (WTLR). This represents a single indicator of the effectiveness of overload mitigation at each bus. It is 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 in different utility control areas, a methodology is needed that compares the transmission benefits of locating power plants at different locations on an unbiased basis.

In basic terms, the 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. All the individual WTLRs added together, make up the Aggregated Megawatt Contingency Overload (AMWCO).

The result is an independent methodology for prioritizing locations for new power plants (conventional and renewable). This allows a comparison in the reduction of the AMWCO for generation located at different WTLR locations. For example, the AMWCO is 10,000 MW. If there are two plant locations, one at 500 kV with a WTLR of 2 that reduces the AMWCO down to 9,500 and the second at 115 kV with a

WTLR of 4 that reduces the AMWCO to 9,000, then the 115 kV site would be selected as the priority location.

An AMWCO is an indication of the reliability of the transmission grid. It should 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.

Using the California transmission power flow model they developed, DPC selected the most logical transmission routing (with respect to kV from the geothermal resources to the nearest hot spots) e.g., metropolitan areas. They calculated the cost of necessary transmission upgrades (e.g. re-conductoring lines up to new transmission lines and/or new substations) to bridge the distance from geothermal resources to hot spots. DPC made some basic assumptions on the size of the power plant(s) to be installed (typically 50MW) but also depended on the resource potential at the site. Transmission costs were distributed over the total number of power plants (e.g. if two 50 MW power plants were installed, the transmission costs were distributed to the total 100MW). Analyzing these costs, the economic model and the GIS maps, staff pinpointed which hot spots could be alleviated using geothermal resources and the amount of MW injection needed for the years indicated.

DPC developed generic transmission and substation costs for various transmission voltages (Table 11). These costs were developed for a double circuit tower with only one transmission line under its initial construction. A second line would increase the projected cost by 25 percent. The transmission costs include the costs for connecting the new line(s) at its respective interconnection point (Table 10). No attempt was made at this level of analysis to adjust the transmission costs for terrain, right-of-way acquisition, or specific conductor size. If the total economics of the power plant are competitive to market prices while lowering the Aggregated Megawatt Contingency Overload (AMWCO), then a more extensive transmission planning analysis must be undertaken. A negative AMWCO impact with a negative Impact Ratio indicates that the AMWCO decreases (reliability improves) with the new generator addition and provides a benefit to the overall reliability of the system. A positive AMWCO with a positive Impact Ratio worsens the reliability of the system.

Table 10: Projected Cost Components for Transmission Lines (2003 Dollars per Mile)

Line Voltage (kV)	Single Circuit	Double Circuit
60-69	$375,000	$468,750
115-138	$800,000	$1,000,000
230-345	$1,700,000	$2,125,000
500-765	$3,300,000	$4,125,000

Source: California Energy Commission Consultant Report written by Davis Power Consultant under contract 500-00-031.

Table 11: Projected Substation Costs (2003 Dollars per MVA)

Substation (kV)	Substation Costs
60/115	$27,500
115/230	$14,000
230/500	$13,600

Source: California Energy Commission Consultant Report written by Davis Power Consultant under contract 500-00-031.

Economic and Location Analysis of Geothermal Sites

Twenty specific geothermal sites were selected for evaluation. The megawatts reflect results from GeothermEx's study described previously. Some of these sites are an expansion of existing geothermal fields while others are new locations which have not been developed to date.

The analysis was completed for 2010 and 2017. For small power plant developments the power flow analysis used the year 2010. This was selected since it provides a better format from which to develop lead times for step increases in unit additions. For large power plant developments, the power flow analysis used the year 2017 since transmission lead times will probably delay commercial operation after 2010.

Analysis of the renewable energy technologies was divided into technology groups. The base-loaded renewables are generators that will have annual average capacity factors of 85 percent or higher. Geothermal technologies were evaluated first and the best locations selected that have both economic and locational value. Some sites may be economical but have little or no value in improving reliability of the overall system. Since the objective of the study is to locate new renewable technologies at locations that provide reliability improvements, some economical sites may not be selected. Furthermore, there may be sites that could provide reliability benefits but have excessive economic costs that eliminated the project from further development until economic factors are not as important.

CDF provided maps of the general location of the geothermal fields and a table showing the closest transmission substation to the field. CDF made an attempt to circle a ten mile area around the field so that new power plants could be located easier.

Since the type of terrain on which new transmission lines would be constructed is unknown, as well as the exact size and configuration of existing substations, general transmission line and substation costs were developed. As more detailed information is known regarding the terrain and the line configurations, these costs should be updated. For now, these generic costs are useful in comparing alternatives and prioritizing site development. In all of the analysis completed, the configuration of the

substations was not considered. There was not any review of the physical configuration of substations as to bus or land space availability.
Out of the 2,955 MW of geothermal sites studied in 2010, 895 MW were eliminated due to high LCOE or positive impact ratios. Table 12 lists the transmission impact ratios. As stated previously, negative impact ratios indicate a reliability benefit to the grid. A positive impact ratio means a detriment to the grid.

Table 12: Geothermal Resource's Transmission Impact Ratios

Geothermal Resource	Trans. Costs Million$	Trans. Impact Ratio	2010 LCOE w/PTC & Trans. Costs (cents/kWh)
Salton Sea	$233	-0.6	5.70
Dunes	$4	-4.2	8.88
Glamis	$16	-1.02	14.93
Superstition Mountain	$1.9	-15.83	6.89
Heber	$4	-4.55	5.72
Niland	$4	-3.97	7.50
Mount Signal	$8	-4.5	6.47
Long Valley Mono County	$33.4	0.64	4.37
Coso Hot Spring Inyo County	$53.1	5.17	7.85
Randsburg	$9.1	5.35	6.49
Brawley	$59.5	-4.42	9.17
Medicine Lake Siskiyou County	$170	-0.48	7.49
Geysers Sonoma County	$53.2	-2.23	8.16
Lake County Geysers and Sulfur Bank Field	$55.9	-2.91	5.74
Calistoga Napa County	$3.8	-1	8.19
Honey Lake	$3.8	0.375	9.84
Lake City/Surprise Valley Modoc County	$4	-1.05	7.41
East Mesa	$4	-5.6	10.22
Total	$679.5		

Source: California Energy Commission Consultant Report written by Davis Power Consultant under contract 500-00-031.

The analysis identifies the resource area and the maximum amount of MW that can be developed to provide the regional/bulk power to areas with generation needs, economically within reach of the geothermal resources, for the target years. For resources with technical potential greater than 50 MW, staff assumed that transmission costs are equally distributed over the entire resource potential capacity instead of, say, the first 50 MW developed. During the transmission modeling, developing certain resources was found to have a detrimental impact on grid reliability i.e. Honey Lake, Coso Hot Springs, Long Valley, Randsburg and Sespe Hot Springs. In addition, despite a high AMWCO benefit, the Dunes, Glamis, and Superstition Mountain sites have small potential.

Geothermal SVA Results

Staff compared the estimated LCOE of the selected resource areas to the LCOE of combined cycle natural gas forecast[9], E3-CPUC[8] forecast, and the Energy Commission's 2003 wholesale price forecast[10] to obtain the economic potential for geothermal. The following summary tables show the LCOE values for 2010 and 2017 for the combined cycle natural gas, the E3-CPUC, and Energy Commission forecasts. It also includes the CPUC market price referent[11]. The economic potential was further reduced by eliminating resource areas with a detrimental impact ratio if developed and connected to the grid.

Table 13: Summary Tables

Constant Dollars ($/kWh)				
Year	Wholesale Price CEC 2003 forecast	Wholesale Price E3-CPUC* Forecast	LCOE Combined Cycle*	Market Price Reference
2005	$0.0316			$0.0605
2006		$0.0674	$0.0693	$0.0605
2010	$0.0426	$0.0630	$0.0742	$0.0605
2017	$0.0587	$0.0716	$0.0915	$0.0605

Source: California Energy Commission, CPUC, Energy and Environmental Economics.

* The analysis for the E3-CPUC and Combined Cycle LCOE was completed by Energy and Environmental Economics, Inc. (E3), and is consistent with the methodology and inputs adopted for the California Public Utilities Commission Avoided Cost proceeding in Rulemaking 04-04-025, April 7, 2005. Details of the methodology and input assumptions can be found on the E3 website at http://www.ethree.com/cpuc_avoidedcosts.html.

2004 Constant Dollars ($kWh)	
Year	LCOE Combined Cycle
2005	
2006	0.06563
2010	0.06286
2017	0.06392

Source: Energy and Environmental Economics

In summary, the analysis conducted by Energy Commission staff, in conjunction with DPC, McNeil Technologies and CDF, resulted in the following estimated economic potential for geothermal using current dollars:

- 1802 MW by 2010, 2638 MW by 2017 (combined cycle comparison)
- 1485 MW by 2010, 1783 MW by 2017 (E3 comparison)
- 0 MW by 2010, 1485 MW by 2017 (wholesale electricity price comparison)
- 1485 MW by 2010, 1513 MW by 2017 (MPR comparison)

Tables 14, 15, 16 and 17 have the breakdown by geothermal resource areas. Using strategic value analysis methodology, an additional 1485 to 2638 MW can be economically developed by 2017 depending upon what price forecast the calculated LCOEs use for comparison.

Table 14: LCOE Compared To Combined Cycle

Known Geothermal Resource Area	County	Technical MW	Current, PTC,w/trs 2010 MW	Current, PTC,w/trs 2010 ¢/kWh	Current, PTC,w/trs 2017 MW	Current, PTC,w/trs 2017 ¢/kWh	Const, PTC, w/trs 2010 MW	Const, PTC, w/trs 2010 ¢/kWh	Const, PTC, w/trs 2017 MW	Const, PTC, w/trs 2017 ¢/kWh
Brawley (sum of Brawley, East Brawley, and South Brawley	Imperial	326.0			326.0	8.35			326.0	6.76
Dunes	Imperial	11.0			11.0	7.44			11.0	6.02
East Mesa	Imperial	74.8			74.8	8.47			74.8	6.86
Glamis	Imperial	6.4								
Heber	Imperial	42.0	42.0	5.72	42.0	4.72	42.0	4.63	42.0	3.82
Mount Signal	Imperial	19.0	19.0	6.47	19.0	5.45	19.0	5.24	19.0	4.41
Niland	Imperial	76.0	76.0	7.50	76.0	6.78	76.0	6.07	76.0	5.49
Salton Sea (including Westmoreland)	Imperial	1400.0	1400.0	5.70	1400.0	5.13	1400.0	4.61	1400.0	4.15
Superstition Mountain	Imperial	9.5	9.5	6.89	9.5	5.73	9.5	5.57	9.5	4.63
	Imperial Total:	1964.7	1546.5		1958.3		1546.5		1958.3	
Calistoga	Napa	25.0			25.0	7.60			25.0	6.15
Geysers [Lake and Sonoma]	Lake & Sonoma	400.0			400.0	7.76			400.0	6.28
Sulfur Bank Field, Clear Lake Area	Lake	43.0	43.0	5.74	43.0	5.16	43.0	4.64	43.0	4.17
	The Geysers Total:	425.0	43.0		468.0		43.0		468.0	
Lake City/ Surprise Valley	Modoc	37.0	37.0	7.41	37.0	6.70	37.0	5.99	37.0	5.42
Medicine Lake (Fieldwide including Fourmile Hill and Telephone Flat)	Siskiyou	304.0	175.0	7.49	175.0	6.88	175.0	6.06	175.0	5.56
Total:		**2857.0**	**1801.5**		**2638.3**		**1801.5**		**2638.3**	

Source: California Energy Commission staff with assistance from McNeil Technologies under contract 500-00-031.

Table 15: LCOE Compared to E3

Known Geothermal Resource Area	County	Technical MW	Current, PTC,w/trs			
			2010		2017	
			MW	¢/kWh	MW	¢/kWh
Brawley (sum of Brawley, East Brawley, and South Brawley	Imperial	326.0				
Dunes	Imperial	11.0				
East Mesa	Imperial	74.8				
Glamis	Imperial	6.4				
Heber	Imperial	42.0	42.0	5.72	42.0	4.72
Mount Signal	Imperial	19.0				
Niland	Imperial	76.0			76.0	6.78
Salton Sea (including Westmoreland)	Imperial	1400.0	1400.0	5.70	1400.0	5.13
Superstition Mountain	Imperial	9.5			9.5	5.73
	Imperial Total:	**1964.7**	**1442.0**		**1527.5**	
Calistoga	Napa	25.0				
Geysers [Lake and Sonoma]	Lake & Sonoma	400.0				
Sulfur Bank Field, Clear Lake Area	Lake	43.0	43.0	5.74	43.0	5.16
	The Geysers Total:	**425.0**	**43.0**		**43.0**	
Lake City/ Surprise Valley	Modoc	37.0			37.0	6.70
Medicine Lake Caldera (includes Fourmile Hill and Telephone Flat)	Siskiyou	304.0				
Fourmile Hill separately	Siskiyou	36.0				
Telephone Flat separately	Siskiyou	175.0			175.0	6.88
Total:		**3068.0**	**1485.0**		**1782.5**	

Source: California Energy Commission staff with assistance from McNeil Technologies under contract 500-00-031.

Table 16: LCOE Compared to Wholesale Price (2003)

Known Geothermal Resource Area	County	Technical MW	Current, PTC,w/trs 2010 MW	2010 ¢/kWh	2017 MW	2017 ¢/kWh
Brawley (sum of Brawley, East Brawley, and South Brawley		326.0				
Dunes	Imperial	11.0				
East Mesa	Imperial	74.8				
Glamis	Imperial	6.4				
Heber	Imperial	42.0			42.0	4.72
Mount Signal	Imperial	19.0				
Niland	Imperial	76.0				
Salton Sea (including Westmoreland)	Imperial	1400.0			1400.0	5.13
Superstition Mountain	Imperial	9.5				
	Imperial Total:	**1964.7**	**0.0**		**1442.0**	
Calistoga	Napa	25.0				
Geysers [Lake and Sonoma]	Lake & Sonoma	400.0				
Sulfur Bank Field, Clear Lake Area	Lake	43.0			43.0	5.73
	2010		**0.0**		**43.0**	
Lake City/ Surprise Valley	Modoc	37.0				
Medicine Lake (includes Fourmile Hill and Telephone Flat)	Siskiyou	304.0				
Total:		**2432.0**	**0.0**		**1485.0**	

Source: California Energy Commission staff with assistance from McNeil Technologies under contract 500-00-031.

Table 17: LCOE Compared to MPR

			Current, PTC,w/trs			
			2010		**2017**	
Known Geothermal Resource Area	**County**	**Technical MW**	**MW**	**¢/kWh**	**MW**	**¢/kWh**
Brawley (sum of Brawley, East Brawley, and South Brawley	Imperial	326.0			.	.
Dunes	Imperial	11.0			.	.
East Mesa	Imperial	74.8			.	.
Glamis	Imperial	6.4				
Heber	Imperial	42.0	42.0	5.72	42.0	4.72
Mount Signal	Imperial	19.0	.	.	19.0	5.45
Niland	Imperial	76.0	.	.	.	.
Salton Sea (including Westmoreland)	Imperial	1400.0	1400.0	5.70	1400.0	5.13
Superstition Mountain	Imperial	9.5	.	.	9.5	5.73
	Imperial Total:	**1964.7**	**1442.0**		**1470.5**	
Coso Hot Springs	Inyo	55.0			.	.
Calistoga	Napa	25.0				.
Geysers [Lake and Sonoma]	Lake & Sonoma	400.0				.
Sulfur Bank Field, Clear Lake Area	Lake	43.0	43.0	5.74	43.0	5.16
	The Geysers Total:	**425.0**	**43.0**		**43.0**	
Honey Lake (Wendel-Amedee)	Lassen	2.0				.
Lake City/ Surprise Valley	Modoc	37.0				.
Long Valley (mono- Long Valley) Mammoth Pacific Plants	Mono	71.0				.
Medicine Lake (sum of Fourmile Hill and Telephone Flat)	Siskiyou	304.0				.
Randsburg	San Bernardino/ Kern	48.0				.
Sespe Hot Springs	Ventura	5.3				.
Total:		**2857.0**	**1485.0**		**1513.5**	

Source: California Energy Commission staff with assistance from McNeil Technologies under contract 500-00-031.

Out-of-State Prospects

Several adjoining states within the Western Electricity Coordinating Council (WECC) have both considerable geothermal potential and an installed base of current capacity. Nevada's geothermal resources presently support twelve electric power plants at ten sites representing approximately 238 MW of electricity capacity (gross). A current study funded by the California Energy Commission PIER Program suggests that Nevada has approximately 2,400MW of technical potential. Indeed, in Nevada's Greater Reno area alone, there is an estimated 1,025MW of technical potential. Utah has 40MW of installed geothermal capacity while Oregon has the technical potential for approximately 2,000MW. In all, there are approximately 7,000MW of potential geothermal capacity in the WECC states.

Table 18 Technical Geothermal Potential, WECC States[12]

State	MW	GWh/yr	%
AZ	601	5,000	8%
ID	601	5,000	8%
NM	360	3,000	5%
NV	2,403	20,000	34%
OR	2,043	17,000	29%
UT	1,081	9,000	15%
Total	7,090	59,000	

Source: California Energy Commission staff with assistance from McNeil Technologies under contract 500-00-031.

Barriers to Geothermal Development

Technical

High Temperature: Practically all components of any hardware system – materials, electronics, mechanical seals, or sensors – are more expensive and more likely to fail when operated at high temperature. Although technology is available to solve some of these problems, the difficulty in designing geothermal equipment is not linear with increasing temperature because there are threshold temperatures for electronics, batteries, seals, and some sensors; these thresholds are below the limits needed for many geothermal resources.

Hard Rock: Drilling hard rock presents a much more challenging environment for almost all geothermal drilling components. The immediate effects are significantly higher forces, impact loads, and vibration levels. Characteristic rock properties also lead to greater wear (geothermal formations often have very high quartz content) and more time spent penetrating in a given interval.

Fractured Rock: The fractured, unhomogeneous nature of geothermal formations requires Wellbore Integrity (WI) technologies to keep the wellbore open, both during drilling (plugging lost-circulation zones and preventing borehole collapse) and after drilling (improved casing cements). WI technologies have been borrowed from other drilling environments – oil and gas, civil engineering, environmental remediation – but these technologies must be upgraded and validated for high temperatures.

For geothermal development, technical challenges to the increased utilization of geothermal resources encompass four distinct aspects of geothermal technology: (1) resource exploration, (2) resource development and completion, (3) drilling, and (4) power generation technology.

Resource Exploration: Improved geophysical methods will lead to a substantial reduction in the number of exploratory and production wells that need to be drilled, thereby dramatically affecting production costs. Improvement will be achieved through increased knowledge of local geology, in large measure gleaned from cross-comparisons to other geothermal fields, but also as a result of more accurate temperature gradient holes. Advances in computer simulation (i.e., fracture mapping) of reservoirs will foster greater accuracy in the identification of large water-filled fractures, thereby reducing risk associated with wildcatting. Further, improved sensors will provide for more accurate and timely information on long-term production processes.

Resource Development: There is a generally limited ability to modify subsurface conditions in order to create sufficient heat flow to recover large amounts of energy. This is a result of the depth from which the energy must be recovered, the relatively low conductivity of rock, and the technical difficulty of engineering satisfactory flow paths in the remote environment.

Drilling. Geothermal drilling is generally conducted in a more hostile environment than wells drilled to a similar depth for oil or gas. Consequently, geothermal well costs are higher than comparable oil and gas wells. Drilling cost reductions are largely a function of the “spill over” from the oil and gas industry. Geothermal well costs should be reduced over the next decade with introduction of advanced drilling technologies (i.e., improved diamond compact bits and mud circulation control), particularly for deep wells as the relative cost of shallow wells will be less impacted.

Furthermore, an additional challenge to the drilling industry will be the changing nature of geothermal reservoirs. A majority of today's geothermal industry believes that the easily accessible resources have already been developed, and that further expansion of the resource base will require deeper drilling as well as engineered reservoir technologies (directional drilling, hydraulic fracturing, fracture mapping, "smart" downhole production technologies, etc.).

Power Generation Technology: Geothermal energy conversion plants face challenges either unique to or exacerbated by the nature of the geothermal fluids and the location of the plants, such as:

- Brine chemistry requires special attention to prevention of fouling, often with inclusion of hazardous materials within the precipitated material. This can also can be viewed as an opportunity to convert dissolved minerals and metals into valuable by-products to provide an additional revenue stream for the plant.

- Materials of construction can be a challenge because of the corrosive nature of geothermal brines and some of the dissolved materials within a geothermal plant. Enhanced materials are required for cost-effectiveness.
- Cycle efficiency is lower for a geothermal plant than for a fossil fuel plant because the brine extracted from the earth is lower in temperature than the heat source for a fossil fueled plant or a nuclear powered plant. Because of this lower cycle efficiency and the costs associated with fluid delivery and disposal, maximizing use of the energy extracted from the geothermal fluid is an important factor in establishing economic viability. Geothermal power plants can benefit greatly from better conversion cycles, components, and operating schemes.
- Heat rejection in a geothermal plant is often a challenge because of the lack of water for cooling, necessitating air-cooling for the plant. Geothermal power plants reject a large amount of heat (about ten times the amount of power generated). This makes a geothermal power plant much more sensitive to the ambient temperature for heat rejection. As a result, the requirement for sensible heat rejection will produce a significant decline in plant output when the ambient temperature becomes elevated, thus enhancing heat rejection or reducing the “sink” temperature.
- Plant size is usually modest for a geothermal plant (typically 30 to 50 MW), necessitating automatic control of plants to minimize operating expense. Plants must be designed for robust operation across a variety of time dependent conditions, reflecting factors such as a decline in reservoir temperature or pressure. It is necessary to minimize operating and maintenance costs via optimized operation.

Incremental improvements in turbines produced for all generation technologies will help reduce costs for geothermal plants. Higher temperature flash systems will not likely experience a large decrease in cost since the technology is reasonably mature. However, binary systems should experience cost reductions associated with improvement in working fluids, more efficient energy conversion with the adoption of “topping” and “bottoming” cycles, and improvement in computer-assisted instrumentation and controls.

Environmental

Air Pollution: Similar to vapor dominated systems, flashed steam plants use evaporative cooling. The sources, types and effects of emissions from flashed steam plants and the abatement technology are nearly identical to those for dry steam plants. Hydrogen sulfide (H_2S) concentrations in liquid-dominated geothermal reservoirs appear to be lower than those found at The Geysers. It is unlikely that

H_2S impact or abatement costs will significantly constrain electrical development in these resource areas. The power plants at Coso Hot Springs are designed to abate 100 percent of H_2S emissions. These include hydrogen sulfide (H_2S), particulates and sulfates. Others are non-criteria pollutants which have potential health effects, but for which no AAQS have been established. These include arsenic, ammonia, benzene, boron, mercury, radon 222, silica, and vanadium. Emissions of noncondensable gases from the geothermal steam, particularly H_2S, can be controlled by external abatement systems that "scrub" the steam before it enters the turbine as well as the condensate when it exits the turbine and before it enters the cooling towers. Hydrogen sulfide is ultimately converted to sulfate particulates and sulfuric acid in the atmosphere. Thus, H_2S has immediate local impacts, and potential regional effects.

Injecting hydrogen peroxide into the vented system controls emissions of H_2S during drilling operations. Steamfield operations also result in H_2S emissions when the power plant is shut down and steam is vented to the atmosphere. H_2S emissions from stacking are controlled by using automatic well throttle controls and interties between units or with a turbine bypass, which channels steam around the turbine to the condenser and subsequent abatement systems.

In addition, the evaporative cooling systems typical at The Geysers release chemicals which have been added to the condensate to reduce corrosion, scaling, and the growth of algae and bacteria. These compounds, which include chromates, chlorine, and acids, may potentially cause significant public health impacts. Other gases emitted from geothermal systems include benzene, mercury, radon, ammonia, and boron.

The design for power plants at the various reservoirs will need to address the potential conflicts between water availability and emissions. Depending on the quality of cooling water used, other emission problems may be encountered. The agricultural wastewater used in plants in the Imperial Valley contains herbicides, pesticides, fertilizers, salts, and other agricultural chemicals. These chemicals are likely to be in cooling tower emissions and deposited on surrounding land. Whether or not cooling tower drift could be a serious problem is not known at this time.

Waste Disposal: Substantial volumes of waste are generated during all phases of geothermal resource development, power plant construction and operation. Toxic wastes are generated from the operation of air pollution abatement systems. The disposed toxic residue from the H_2S abatement process was minimized at the Imperial Valley resource. All hazardous waste must be disposed of in Class I Waste Management Units, and designated wastes can be disposed of in either Class I or II waste sites.

Waste is also produced during drilling; these wastes include drilling mud, rock cuttings, drilling mud additives, lost circulation materials, cement, H_2S abatement chemicals, and oily residues. In addition, the sludge deposited in cooling towers and produced from water treatment is contaminated with lead, zinc, arsenic, mercury, and other compounds. These wastes must be treated as hazardous.

Water Pollution: Water quality issues include potential contamination of surface water and groundwater from extraction and reinjection wells, and possible consumption of surface water resources to recharge the geothermal reservoir. Most high temperature geothermal waters are saline and contain toxic trace contaminants such as boron, arsenic, mercury, ammonia, and lead. These fluids also contain iron and manganese, which produce acidity.

Construction of roads, well pads, and power plants can accelerate erosion, which increases stream turbidity and sediment deposition. Soil losses from disturbed areas have been estimated at 20 times predisturbance erosion rates, although revegetation and site stabilization decrease long-term erosion rates. In addition, spills from power plant and field operations have been a source of stream water quality degradation. However, recent changes in plant operation practices and controls, combined with a reduction in the quantity of transported hazardous materials, have reduced the number of spills.

Noise Pollution: Noise limits and requirements to use the best available control technology (BACT) for noise abatement are generally dictated by the local county through use permits. Generally, as geothermal development moves closer to sensitive receptors, the required performance levels and costs of BACT will increase proportionately. High frequency noise emissions as a result of drilling may be a factor. Noise levels from different activities can range from 75 to 120 decibels, 50 feet from the source.

Destruction / Disturbance of Habitat: Most of the habitat loss is attributable to the construction of roads, wellpads, and steam lines. Surface erosion, ground water siltation, and habitat disturbance may result from resource development. Like other large-scale engineering projects, geothermal field development results in disruption of land surfaces and ecosystems, increased erosion, and dust generation. Common land disruptions occur from the grading and construction of roads and geothermal plant sites. The severity of these impacts depends upon the project's scale, its location, and mitigating measures taken. A primary effect on land is the area required for exploration and facility siting. While energy production may require only about 20 to 100 acres, the exploration drilling, construction, and operation together require from 500 to 3,000 acres.

The potential for such alteration to conflict with natural scenic qualities is increased by engineering and economic factors that often argue for the siting of geothermal facilities at visually prominent locations (e.g., ridgelines). Methods available for reducing these conflicts include minimizing cuts and fill, contouring with natural topography, clustering wells on single well pads, routing pipelines along roads, painting facilities natural colors, and using vegetation for screening.

Land Subsidence: The withdrawal of large quantities of underground water can cause ground subsidence. This disruption can cause tilting and stressing of pipelines and surface structures. Land subsidence can occur on extensively irrigated and drained farm land. Reinjection of water into the ground, or reinjection of geothermal fluids, can counter this problem. Less subsidence is expected with harder reservoir rock.

Subsidence of the ground surface has been observed at several areas where extraction of geothermal fluids has caused the subsurface reservoir to contract. The resource area most sensitive to subsidence is the Imperial Valley where the extensive irrigation and wastewater drainage agricultural development could be adversely affected by subsidence. Imperial County has a policy requiring 100 percent injection of the fluids withdrawn from a geothermal reservoir, but permits most power plants with an injection requirement of 80 percent or more.

Lack of Suitable Sites: Due to the mountainous terrain of The Geysers area and the need to site power plants relatively close to steam resources, there is a growing shortage of suitable sites for large central plants. Preferred sites have historically been on ridgetops where solid bedrock can provide a strong foundation. Ridgetops, however, can pose visual, erosion, and sedimentation problems. As development moves to less preferred sites, the costs to mitigate these problems will increase. Additional suitable sites exist for smaller modular plants. As the required space decreases, the availability of sites increases. The cost of required mitigation measures decreases.

Availability of Water: Surface and groundwater is very limited in Lake and Sonoma counties. Geothermal developers must compete not only with commercial and agricultural interests but also, in the case of Lake County, with neighboring jurisdictions with rights to surface and groundwater. Current power plant design uses condensed steam as cooling water. Most is lost through evaporation and only 15 to 20 percent is injected back into the aquifer. This has resulted in reservoir pressure drops at some sites.

At The Geysers, production declines could be substantially improved by injection of water from external sources. However, during a multi-year drought, competition with rural farms and urban residences for water led to shut-in capacity rather than recharging of the aquifer. Use of treated sewage effluent has supplied needed recharge via the Santa Rosa and the Southeast Geysers Pipeline projects.

Institutional

Environmental Impact Statement and Permitting / Leasing: Significant facility siting issues are impeding development of geothermal energy resources throughout the United States. The entire process, from site exploration through plant operation could take more than a decade with permitting processes accounting for a large fraction of the time. In particular, the environmental impact statement (EIS) may take over two years, while permitting and leasing can take even longer. It is not unusual for firms to redo EIS work because information has become out of date during the entire process.

Several federal and state agencies are prominent in the geothermal siting process, including the U.S. Department of the Interior (U.S. Bureau of Land Management, Fish and Wildlife Service and the Bureau of Indian Affairs), U.S. Department of Agriculture (U.S. Forest Service), and in California the California Energy Commission (which sites all facilities >= 50MW including those on Federal lands).

The diversity of decision makers leads to a long process in which conflicting goals may be encountered.

Further, compliance with Section 106 of the Historic Preservation Act is often cited as a time-consuming process.[13] Of particular significance in California, Section 106 concerns were instrumental in the recent efforts by Calpine to develop the resource at Telephone Flat. Recognition of the Medicine Lake Area Traditional Cultural Places District was responsible for relocation of transmission lines and new road construction to minimize impact.

Low End User Awareness for New Technologies (i.e. Kalina Cycle, Hybrid air cooled and water cooled condensers): These machines are radically different than steam or vapor turbines normally used to generate electrical power from geothermal sources. They are maintained and operated differently, and operators and developers may be resistant to adopting this technology.

Environmental Benefits: Few studies have tried to assign value to geothermal energy externalities (e.g., benefits/costs of environmental impacts). Lack of a solid connection between the siting process and the federal commitment to renewable energy and global warming initiatives is stark and hinders effective policy execution. Literature addressing the environmental costs and benefits is scarce.

Local Populace Reactions (NIMBY): Geothermal development is affected by many of the same issues surrounding the siting and operation of other industrialized facilities that utilize natural resources, including

- Conflict with local beliefs or traditions, such as Hawaii and Glass Mountain (Pumice Mine and Telephone Flat), may affect development. This is particularly true for sites with Historic Preservation Act designation.
- Geothermal sites are often located in remote areas, necessitating construction of new roads and transmission lines. Development on environmentally sensitive or undisturbed lands is increasingly difficult and/or expensive.
- Drilling noise may require sound abatement equipment or restrict hours of operation.
- Gases released may require pretreatment.

Regulation: (a) Reform of the Public Utility Company Act (PUHCA) may afford additional opportunities.

(b) National park areas contain unavailable resources, which limits development of geothermal power.

(c) Regulatory movement toward least-cost planning, with inclusion of benefits (externalities), could encourage development.

Economics

Three major cost components characterize geothermal development: (1) resource exploration, (2) wellfield development including NEPA siting process, and (3) power generation equipment. Existing facilities at the Geysers are among the least expensive base load facilities. Future installations will utilize less favorable resources and will be incur commensurately higher capital and operating costs relative to the Geysers. Because the fuel costs are essentially zero, new installations are particularly sensitive to finance rates.

Over the past several years, interest in smaller-scale geothermal installations has increased. There are at least two commercial firms producing small-scale units, Ormat and Exergy. NREL is cost-sharing the design and construction of several small (up to 1 MW) installations.[14] These facilities represent a variety of power generation technologies including binary-cycle, Kalina-cycle, and flash installations. Furthermore, many of the installations plan to use the by-product warm waters for direct use applications. Projected installed costs range from $2,600 to $3,400/kW. The projected cost of energy for the facilities ranges from $0.06 - $0.09/kWh.

Benefits of Geothermal Resources Development

In addition to cost benefits of strategically building geothermal power plants to serve transmission hot spots, there are air quality and employment benefits that can be quantified assuming the MW injection provided in the previous section.

Environmental

Cleaner Air and Reduced Greenhouse Gas Emissions: Unlike conventional power plants, geothermal power plants emit benign levels of air pollutants. Geothermal power plants exceed stringent clean air standards because no nitrogen oxides are emitted and very low amounts of sulfur dioxide are released. In comparison to fossil fuel plants, geothermal facilities emit minimal amounts of carbon dioxide, 1/1000 to 1/2000 of what is produced by fossil-fuel plants. Other gases released may include hydrogen sulfide, which are in such low concentrations that it requires no special controls to comply with strict state and Federal limits. Typical emissions of hydrogen sulfide from geothermal plants are less than 1 part per billion.

Reduced Land Use: With respect to land use, geothermal facilities require less land in comparison to coal and nuclear plants. This advantage is especially notable when compared to mining operations. A typical geothermal plant requires several wells. Directional or slant drilling can minimize land impacts. This allows for multiple wells to be drilled from one drilling pad, minimizing the amount of land needed for access roads, geothermal fluid piping, and construction. The technology is relatively expensive compared to routine vertical drilling.

Air Quality: Geothermal power plants have less emission compared to fossil power plants.

Table 19: Projected Avoided Emissions

Year	2003	2005	2007	2010	2017
Capacity (MW)	1,953	1,953	1,953	1,953	1,953
Capacity Factor	86%	86%	86%	86%	86%
Percent of Peak Load	3.8%	3.8%	3.7%	3.5%	3.5%
Generation (GWh)	14,723	14,723	14,723	14,723	14,723
Percent of Generation	5.1%	5.0%	4.9%	4.6%	4.6%
Employment (#)	3,821	3,261	3,261	3,261	3,261
Avoided Emissions					
CO_2 (Tonne/day)	27,269	27,269	27,269	27,269	27,269
NO_x (Tonne/day)	8.70	8.70	8.70	8.70	8.70
SO_x (Tonne/day)	0.58	0.58	0.58	0.58	0.58
CO (Tonne/day)	7.73	7.73	7.73	7.73	7.73
TOG (Tonne/day)	5.71	5.71	5.71	5.71	5.71
ROG (Tonne/day)	0.92	0.92	0.92	0.92	0.92
PM (Tonne/day)	1.02	1.02	1.02	1.02	1.02
PM10 (Tonne/day)	0.92	0.92	0.92	0.92	0.92

Source: California Energy Commission report “California Renewable Technology Market and Benefits Assessment,” November 2001, G. Simons.

Economy

Job Creation: California’s geothermal industry has provided economic and employment benefits. Over the last forty years over $5 billion has been invested in constructing geothermal electrical facilities in California. This expenditure has supported over $15 billion in Gross State Product, $4.5 billion in payroll, $1 billion in state taxes, and well over 100,000 jobs. Geothermal energy provides valuable supplies of electricity to the electrical system grid in capacity-strained areas, and has deferred the need for the construction of new and expensive transmission and distribution upgrades. For many communities geothermal power facilities create jobs, generate income and support economic development.

Stable Energy Prices: By investing in geothermal energy development, California can economically benefit from a homegrown industry that can both provide clean electricity to California as well as exporting power and technology to other regions. Geothermal power plants consume no fossil fuels; therefore most of the cost of geothermal generation is known when the systems are installed. Geothermal power plants maintain predictable annual operating costs, since they are not subject to the risks of fuel price fluctuations as are plants fired by fossil fuels.

Table 20: Finance Costs

Category	Units	Value
EXPENSES		
Royalty Rate	% of annual revenue	3%
Avg. wholesale electricity price	$/kWh	$ 0.0429
TAXES		
Federal Tax Rate	%	34.00
State Tax Rate	%	6.50
Combined Tax Rate	%	38.29
Investment Tax Credit	%	10%
Production Tax Credit (five years)	$/kWh	$ 0.0180
Property Tax Rate	%	2%
ESCALATION/INFLATION		
General Inflation	%	2.80
Escalation--Fuel	%	5.00
Escalation--Other	%	2.80
FINANCE		
Debt ratio	%	66.67
Equity ratio	%	33.33
Interest Rate on Debt	%	9.00
Life of Loan	Years	20
Cost of equity	%	18.00
Cost of Money	%	12.00
Debt Reserve	$	one year
ACRS DEPRECIATION	Years	6

Source: California Energy Commission staff with assistance from McNeil Technologies under contract 500-00-031.

Projected Economic Impacts: Forecasts for additional geothermal capacity installations in 2010 and 2017 have associated economic impacts. As presented in Table 11, increases in employment and taxes are projected to be on the order of 5,000 new jobs and almost $60 million in tax revenues.

Table 11: Projected Economic Impacts Associated with Geothermal Development

Category	2010	2017	Total
Employment (#)	944	4,084	5,029
Taxes ($Million)	$ 11.0	$ 47.4	$ 58.4
Emis. Ben. ($Million)	$ 27.2	$ 123.1	$ 150.3
Total Benefits ($Million)	$ 38.2	$ 170.5	$ 208.7
Source: California Energy Commission Consultant Report written by Davis Power Consultant under contract 500-00-031.			

Summary

Geothermal energy provides significant benefits in terms of improved air quality, increased diversity in electric energy sources, local and state revenues, and employment. California has the largest geothermal installed capacity in the country with approximately 1,900 MW. In addition, California has the potential to double the installed capacity by 2017 from resource areas such as Imperial Valley, The Geysers and Glass Mountain. Imperial County has 11 KGRAs including Brawley, Salton Sea, and East Mesa. Using the strategic value analysis methodology, an additional 1485 MW to 2638 MW can economically be developed by 2017 depending on what price forecast the calculated LCOEs for geothermal is compared with. With the RPS and the PTC in place, geothermal development is poised to increase dramatically within the next decade.

Endnotes

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

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

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

[4] Material from this section was adapted from the CEC Consultant Report written by GeothermEx, "New Geothermal Site Identification and Quantification"

[5] Material from this section was adapted from the CEC Consultant Report written by GeothermEx, "New Geothermal Site Identification and Quantification"

[6] The section 45 tax credits (PTC) were extended when HR 4520 (American Jobs Creation Act) was enacted on 22 October 2004. Geothermal, solar, wind, and closed loop biomass are eligible for the 1.5 cents/kWh credit indexed for inflation (now at 1.8 cents/kWh).

[7] The section 45 tax credits (PTC) were extended when HR 4520 (American Jobs Creation Act) was enacted on 22 October 2004. Geothermal, solar, wind, and closed loop biomass are eligible for the 1.5 cents/kWh credit indexed for inflation (now at 1.8 cents/kWh).

[8] The section 45 tax credits (PTC) were extended when HR 4520 (American Jobs Creation Act) was enacted on 22 October 2004. Geothermal, solar, wind, and closed loop biomass are eligible for the 1.5 cents/kWh credit indexed for inflation (now at 1.8 cents/kWh).

[9] The analysis for the E3-CPUC and Combined Cycle LCOE was completed by Energy and Environmental Economics, Inc. (E3) and is consistent with the methodology and inputs adopted for the California Public Utilities Commission Avoided Cost proceeding in Rulemaking 04-04-025, April 7, 2005. Details of the methodology and input assumptions can be found on the E3 website at http://www.ethree.com/cpuc_avoidedcosts.html.

[10] Electricity Infrastructure Assessment Report, May 2003 pp 15-19.

[11] http://www.cpuc.ca.gov/published/rulings/43824.htm

[12] California Energy Commission, Renewable Resources Development Report, September 30, 2003, page 61. Energy values, GWh, were converted to capacity, MW, by assuming a 95% capacity factor.

[13] The National Historic Preservation Act of 1966, amended in 1992, establishes a Federal policy of encouraging preservation of cultural resources for present and future generation. The Federal lead agency of r proposed action is responsible for initiating the "Section 106" review process and for consulting with the State Historic Preservation Officer (SHPO) and the Advisory Council on Historic Preservation.

[14] C. Kutscher, "Small-Scale Geothermal Power Plant Field Verification Projects," NREL/CP-550-30275, National Renewable Energy Laboratory, June 2001.