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2007 ENVIRONMENTAL PERFORMANCE REPORT OF CALIFORNIA'S ELECTRICAL GENERATION SYSTEM

Prepared in Support of the *2007 Integrated Energy Policy Report* Proceeding (06-IEP-1)

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ABSTRACT

The *2007 Environmental Performance Report of California's Electrical Generation System* assesses the environmental performance of California's fleet of about 1,000 power plants totaling nearly 67,000 megawatts. It is a supporting Energy Commission staff report to the *2007 Integrated Energy Policy Report* and provides information on five environmental subject areas for consideration by the California Energy Commission: cooling water use at California power plants; once-through cooling regulatory and policy issues at coastal power plants; biological resource issues associated with solar thermal and other renewables development in desert habitats; an update on the development of guidelines to reduce avian mortality at wind farms; and energy and economic analyses of the Klamath River Hydropower Project.

Keywords: Environmental performance, environmental impacts, avian mortality, desert ecosystems, renewable energy, wind turbines, solar thermal, cooling water, once-through cooling, Klamath River, hydroelectric project.

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PREFACE

The *2007 Environmental Performance Report* is a supporting staff report to the California Energy Commission's *2007 Integrated Energy Policy Report*. The legislative intent for the Environmental Performance Report series is to provide ongoing status and trends information on the environmental performance of California's nearly 67,000 megawatt (MW) power generation fleet of about 1,000 power plants as it evolves in response to the initial energy deregulation policies of 1996. The chapter on once-through cooling is intended to serve as the basis for a status report to the California Legislature, as required by AB 1576 (Nunez, Statutes of 2005), on the progress being made to implement the once-through cooling performance standards as established by the U.S. Environmental Protection Agency under Section 316(b) of the Clean Water Act.

The *2007 Environmental Performance Report* is the fourth in a series of biennial reports that began in 2001. This year's report describes California's evolving in-state generation resource mix and electricity imports and provides information to the California Energy Commission on five environmental topics related to electrical power generation that can contribute information to the *Integrated Energy Policy Report*: cooling water use by California power plants; once-through cooling issues associated with California's coastal power plant fleet; biological resource issues associated with the development of solar thermal and solar photovoltaic facilities in California; an update on guidelines to reduce avian impacts associated with wind farms; and Klamath River Hydroelectric Project energy and economic analyses associated with the Federal Energy Regulatory Commission (FERC) Relicensing Proceeding.

The key findings and trends developed in the 2005 report on air emissions, land use, socio-economics, cultural resources, the electric transmission system, and hydropower system impacts are still germane to an understanding of the environmental performance of California's electrical generation system.

The general conclusion from the *2005 Environmental Performance Report* was that the environmental performance of California's large and diverse electrical generation system is good and continues to improve. The environmental footprint of the system is relatively small compared to other parts of the country and to the rest of the world, especially given the size and continuing economic growth of the state. Most notably, air emissions from California's thermally-fired power generation fleet are highly controlled and comprise very small elements of the air emissions inventory for most California air basins. At the statewide level, generation-related oxides of nitrogen (NOx) emissions for 2004 comprised 1 percent of all NOx emissions. In most air districts, power plant emissions are no longer a principal driver of air quality or attainment planning.

Summary of the 2007 Environmental Performance Report

Cooling Water Use by California Power Plants: On a capacity basis, 69 percent of the power plants proposed to the Energy Commission since 2004 will use recycled water or air cooling, up from 37 percent for the proposals submitted between 1996 and 2003. No large combined cycle projects are proposing to use fresh surface water or groundwater for cooling, and no new coastal power plant repower projects propose to use once-through cooling. Nine new power plants totaling 4,455 MW propose to use air cooling, and 10 projects totaling 4,536 MW have submitted applications to use recycled water since 2004.

Once-Through Cooling at Coastal Power Plants: Recent federal court decisions and proposed regulatory actions by California state agencies may lead to an eventual phase out of once-through cooling at most of California's 17 natural gas-fired coastal plants. Between 2006 and 2007, five coastal plants comprising nearly 30 percent of the coastal gas-fired fleet announced plans to switch from once-through cooling to air cooling. California's two operating nuclear power plants use once-through cooling. Due to their size, costs and unique role in contributing to grid stability and fuel diversity, the nuclear plants present special circumstances that need to be evaluated carefully before new regulations on once-through cooling are finalized in California.

Expansion of Renewables Fleet: Renewable energy resources such as wind, solar thermal, solar photovoltaic and geothermal may increase rapidly from the 2006 level of 7,623 MW in order to meet Renewable Portfolio Standard and greenhouse gas reduction goals; from 15,000 MW to 38,000 MW could be added by 2020.

Potential Biological Resource Impacts from Renewable Energy Development: Significant impacts to sensitive ecosystems and wildlife species may occur from the potentially large increase in renewable energy projects because renewable energy technologies typically require more land area per MW than fossil-fueled or nuclear generation (assuming a non full-fuel-cycle assessment), and because large renewable projects tend to be located in rural areas. The Energy Commission is working to ensure that such impacts are avoided or minimized. Energy Commission staff worked with the Department of Fish and Game to produce the voluntary *California Guidelines to Reduce Impacts to Birds and Bats from Wind Energy.* Energy Commission staff have also developed a Memorandum of Understanding with the U.S. Bureau of Land Management to facilitate environmental review of a possible 38,000 MW of solar thermal and solar photovoltaic projects in the California desert. Based on Energy Commission staff data, these new solar generation technologies could require about 308,000 acres, or 480 square miles, which would represent about 1.4 percent of the total land space of the California desert.

Klamath Hydroelectric Project: The Klamath River Hydroelectric Project causes significant impacts to endangered Chinook salmon, coho salmon, steelhead trout and many other endangered species on what was historically the third largest salmon river on the West Coast of the United States. Energy Commission staff consultant studies conducted in support of ongoing settlement negotiations and the Federal Energy Regulatory Commission's relicensing proceeding show that decommissioning the Klamath Hydro Project and buying replacement power for 30 years is from $32 million to $286 million less costly than installing extensive mitigation measures likely to be required by state and federal fisheries and water quality agencies ($114 million less costly for the midline case) if the facilities are relicensed.

CHAPTER 1: Introduction

The legislative intent for the Environmental Performance Report series is to provide ongoing status and trends information on the environmental performance of California's power generation fleet as it evolves in response to the initial energy deregulation policies of 1996. This report assesses the environmental performance and related impacts of California's nearly 67,000 megawatt (MW) electrical generation system.

The *2007 Environmental Performance Report* is a supporting staff report to the Energy Commission's *2007 Integrated Energy Policy Report*. The chapter on once-through cooling is intended to serve as the basis for a status report to the California Legislature, as required by Assembly Bill 1576 (Nunez, Statutes of 2005), on the progress being made to implement the once-through cooling performance standards as established by the U.S. Environmental Protection Agency under Section 316(b) of the Clean Water Act.

The *2007 Environmental Performance Report* is the fourth biennial report in this series that began in 2001. This year's report provides brief updates on California thermal and renewable power plant development and electricity imports, and provides information on five specific environmental topics as input to the *2007 Integrated Energy Policy Report*: 1) cooling water use by California power plants subject to Energy Commission siting jurisdiction; 2) once-through cooling issues associated with California's coastal power plant fleet; 3) biological resource issues associated with solar thermal facilities in California; 4) guidelines to reduce avian mortality at California wind farms; and 5) Klamath Hydroelectric Project energy and economic analyses associated with the Federal Energy Regulatory Commission (FERC) Relicensing Proceeding.

Staff used data from Energy Commission power plant licensing cases and other internal data sets and reports for the *2007 Environmental Performance Report*. Staff did not solicit environmental or operational data from power plant operators, as was done in 2005.

The *2007 Environmental Performance Report* does not include new analytic work on the California energy system, air emissions, land use, socio-economics, cultural resources, the electric transmission system or hydropower system impacts, as was done for the 2001, 2003, and 2005 reports. Generally, the key findings and trends for these topics are still germane to an understanding of the environmental performance of California's electrical generation system.

Progress-to-Date on Key Issues Identified in the 2005 Environmental Performance Report

Once-Through Cooling at California's Coastal Power Plants: Based on information in the 2005 Energy Commission staff white paper, *Issues and Environmental Impacts Associated with Once-Through Cooling at California's Coastal Power Plants*, the California Energy Commission determined in the *2005 Integrated Energy Policy Report* that once-through cooling "can contribute to the decline of fisheries and the degradation of estuaries and bay and coastal waters." The Energy Commission directed staff to work cooperatively with other state agencies to address once-through cooling issues in the broader context of protecting the state's fragile coastal marine ecosystem.

Since 2005, Energy Commission staff has provided substantial technical information on coastal power plant operations, grid reliability and resource adequacy, and scientific methods for assessing and mitigating impacts to marine and estuarine ecosystems from once-through cooling to the state agencies involved with once-through cooling. This information has been provided to the California State Water Resources Control Board in response to their Proposed Policy on Clean Water Act 316(b) Regulations, to the Ocean Protection Council in support of its resolution and studies related to once-through cooling, and to the California Independent System Operator in support of its studies on the replacement of aging steam boiler power plants, which includes 17 fossil-fueled coastal plants.

Energy Commission Siting Program staff finalized the assessment and mitigation recommendations for the Huntington Beach power plant, which culminated in a license condition for purchase and restoration of 66.8 acres of tidal wetlands in Southern California at a cost of $5.5 million. Staff also completed a consultant report, *Assessing Power Plant Cooling Water Intake System Entrainment Impacts,* which describes state-of-the-art methodologies for assessing entrainment impacts.

Since 2005, Energy Commission Public Interest Energy Research Program staff has managed $1.5 million in research funding for a series of scientific investigations into impacts from once-through cooling.

Impacts to Avian Species from Wind Turbines: In the *2005 Environmental Performance Report*, Energy Commission staff reported that 1) wind farms and the transmission line systems needed to link them to the grid were projected to expand to help meet California's Renewable Portfolio Standard goals, 2) bird mortality from strikes with wind turbine blades continued to be the primary biological resource issue concerning wind energy, and 3) fragmented jurisdiction between local, state, and federal agencies and non-coordinated regulatory programs contributed to an inefficient regulatory approach to understanding statewide impacts. The Energy Commission recommended in the *2005 Integrated Energy Policy Report* that "statewide protocols should be developed for studying avian mortality to address site-specific impacts in each individual wind resource area."

In response to the Energy Commission's direction, staff collaborated with the California Department of Fish and Game to develop the voluntary *California Guidelines for Reducing Impacts to Birds and Bats from Wind Energy Development.* The *Guidelines* are intended to encourage the development of wind energy in the state while striving to minimize impacts to birds and bats. The *Guidelines* were approved by the Energy Commission at the September 26, 2007 Business Meeting.

Out–of-State Power: In the *2005 Environmental Performance Report* white paper, *Preliminary Environmental Profile of California's Electricity Reports*, staff reported that in an average year, California imports from 20 to 30 percent of its electricity from out-of-state generating units, and that California utilities own about 6,200 MW in out-of-state resources, including 4,744 MW of coal-fired power plants. Staff determined that emissions from the generation facilities providing electricity imports are four times higher than in-state generation; the average NOx emission rate for fossil-fueled electricity imported to California is 1.4 pounds per MWh, while the California NOx emission rate averages 0.36 pounds per MWh. Staff concluded that "energy imported from the western states includes a significant amount of coal-fired power that creates significantly higher emissions per MWh than California power sources."

Since 2005, Energy Commission staff has contributed to a key regulatory effort to reduce greenhouse gas emissions associated with imported electricity from coal. Senate Bill 1368 (Perata, Statutes of 2006) required the Energy Commission to work cooperatively with the California Public Utilities Commission and California Air Resources Board to establish a greenhouse gas emission performance standard for the state's public owned electric utilities. During the Energy Commission's rulemaking, staff established a performance standard of 1,100 pounds of carbon dioxide per megawatt-hour. The new regulations will prohibit the state's local publicly-owned electric utilities from entering into long-term financial commitments with power plants that exceed the emissions performance standard for greenhouse gases. The Office of Administrative Law approved the new regulations on October 16, 2007.

Hydropower Impacts to Inland Rivers and Streams: Staff reported in the *2005 Environmental Performance Report* that "development and operation of California's 13,326 MW hydroelectric system has created significant, on-going, under-mitigated impacts in rivers and streams. Consequently, many riverine ecosystems have been altered and degraded to the extent that they can no longer support populations of wild salmon, steelhead, or native trout."

Staff's primary work on hydropower impacts to endangered salmon and aquatic ecosystems has focused on the Klamath Hydroelectric Project in Northern California and Southern Oregon. The 2006 Energy Commission Consultant Report, *Economic Modeling of Relicensing and Decommissioning Project Options for the Klamath Basin Hydroelectric Project*, is a ground-breaking economic analysis of two future project options for the Klamath Hydro Project: relicensing with extensive mitigation measures to protect endangered salmon population, and decommissioning with procurement of replacement power for 30 years. The results of the study have been provided to the Federal Energy Regulatory Commission, the public utilities commissions in California, Oregon and Washington, and PacifiCorp. Energy Commission staff and their lead consultant, Dr. Richard McCann of M.Cubed, have provided technical economic and energy analysis support to the government negotiating team working within the confidential settlement negotiations on potential decommissioning of the hydropower project.

Summary of the Initial Environmental Performance Reports

The *2001 Environmental Performance Report* provided an initial evaluation of the environmental performance of the state's electrical generating system from World War II to the year 2000. Environmental performance improved substantially during that time period, primarily due to switching from oil to natural gas, improvements in combustion technologies, and implementation of pollution controls. The *2003 Environmental Performance Report* focused on the performance of the system between 1996 and 2002, during which time the changes from deregulation of the state's energy markets were enacted. The *2003 Environmental Performance Report* improved the analytic methods and data sources from the first report, established a quantified 1996 environmental baseline, and identified lack of sufficient environmental data as a major hindrance for assessing changes in environmental performance. The *2003 Integrated Energy Policy Report* adopted two policy options from the staff report: a policy change on the use of fresh water for power plant cooling, and encouragement of ongoing Energy Commission staff support to state agencies working on hydropower re-licensing.

In 2005, Energy Commission staff expanded the scope of investigations beyond earlier reports and provided comprehensive analysis of power plant emissions within California. The 2005 Report also included major white papers on once-through cooling, out-of-state power, avian mortality at wind farms, and climate change effects on hydropower production:

- *A Preliminary Environmental Profile of California's Imported Electricity*
- *Issues and Environmental Impacts Associated With Once Through Cooling At California's Coastal Power Plants*
- *An Assessment of Avian Mortality From Collisions and Electrocutions*
- *Potential Changes In Hydropower Production From Global Climate Change In California and the Western United States*

The general conclusion from the 2005 Report was that the environmental performance of California's large and diverse electrical generation system is generally good and continues to improve. The environmental footprint of the system is relatively small compared to other parts of the country and to the rest of the world, especially given the size and continuing economic growth of the state.

Environmental Data Collection

Compiling the appropriate operational and environmental data for nearly 1,000 power plants is a complex endeavor. Energy Commission staff uses environmental data from existing databases at the Energy Commission and other state and federal agencies as much as possible. However, there is a great deal of inconsistency in how data are collected and reported. For example, power plant-level and generating unit-level data for air emissions and criteria pollutants are compiled by the California Air Resources Board, the U.S. Environmental Protection Agency and by the Energy Commission. In contrast, there is little consistency in water use and water quality information for power plants, and nearly no centralized information on biological resource impacts to terrestrial and aquatic ecosystems affected by thermal, renewable or hydroelectric power plants.

In 2005, Energy Commission staff solicited environmental data for air emissions, water use, waste water discharge, biological resources, hydropower operations and socioeconomics directly from owners of all power plants one MW or larger. Data responses were received from 453 power plants totaling 53,441 MW. While the responses included a large part of the California fleet on a capacity basis, the data quality proved to be inconsistent and problematic.

In 2007, the Energy Commission adopted new regulations for energy-related data collection. Included in the final regulations are authorization to solicit annual water use and waste water discharge data from all power plant owners. Energy Commission staff plans to begin collecting this water data for the *2009 Environmental Performance Report.*

Environmental Performance

"Environmental performance" for energy systems consists of several factors:

- Thermal efficiency
- Environmental discharges
- Environmental quality effects
- Environmental efficiency

Thermal efficiency is the measure of the effectiveness of converting the heat content of various fuel sources to electrical energy. Environmental efficiency is the measure of units of environmental discharge and impact per unit of energy produced. Environmental emissions and discharges are the measure of tons of pollutants emitted to air, acres of habitat displaced, or gallons of water used. Discharges create varying levels of impact to environmental quality. A given power generation facility can cause varying levels of impact to an air basin, watershed or ecosystem.

Thermal efficiency, environmental efficiency and rates of environmental discharge result from changes in generation and pollution control technology, economics, changes in environmental regulation, and changes in scientific understandings of natural systems

Understanding and documenting the contributions of California's power generation and transmission system to environmental quality trends for air, water and biological resources in specific geographic locations is a long-term goal for the Energy Commission. The data, analytic capacity and staff resources required for such an assessment are probably beyond the means of any single agency.

CHAPTER 2: Update on California's Electricity Resource Mix

Capacity and Generation

California's electricity system is powered by a large, diverse mix of generating resources that currently measures about 67,000 MW of installed, nameplate capacity from a fleet of nearly 1,000 power plants. In-state generation is supplemented by imports from the Southwest (primarily coal, nuclear, and natural gas) and Northwest (primarily hydro with some coal and gas) that average about 20 percent of the state's total demand but that can reach 30 percent in some years. Total electricity consumption in California for 2006 was 294,865 gigawatt-hours (GWh).

Figures 1 and 2 show total 2006 electricity consumption by fuel type for the in-state production, out-of-state coal plants owned by California utilities, and imports (Figure 2 further disagregates the 64,763 GWh of imported electricity shown in Figure 1 by fuel type). Due to the closure of the coal-fired Mohave Generating Station in Nevada in late 2005, which was owned by Southern California utilities, coal generation classified as "in-state" decreased by more than 10,000 GWh from 2005. This reduced the level of coal generation attributed to California utilities from its historic average of 10 percent to 6 percent in 2006. Due to the heavy Sierra snowpack in the 2006 water year, generation from hydropower increased by 8,990 GWh in 2006, and comprised 21 percent of total electricity consumption (in-state generation plus hydro imports).

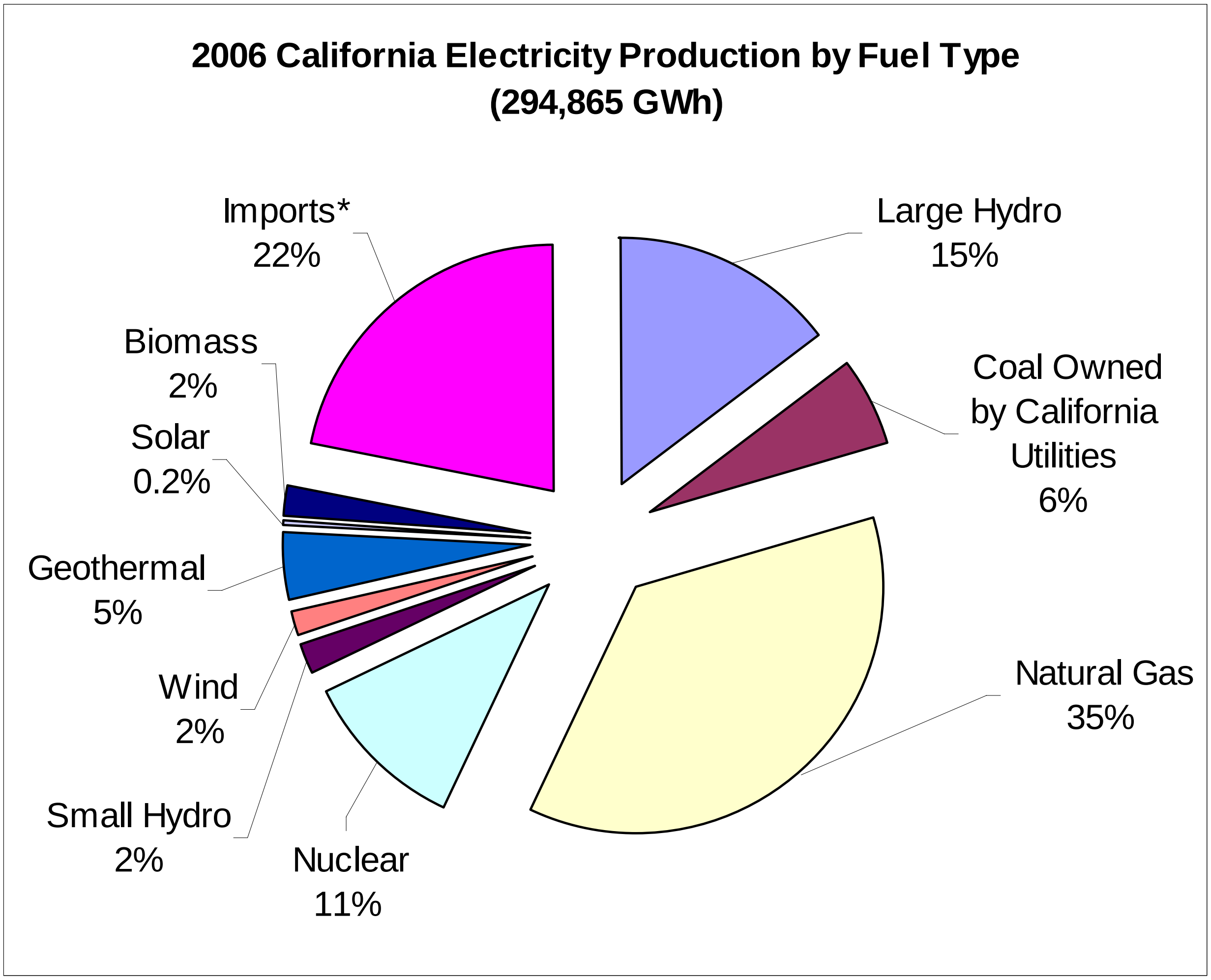
Table 1 and Figure 3 show California's in-state generating resources by capacity and generation technology for 2006 (Note that the wind capacity figure is for 2007). The important difference between electricity actually consumed and the capacity needed to produce this electricity are explained below.

For environmental performance assessment, both nameplate capacity (installed MW) and energy production (MWh) are used. Installed capacity denotes the design capacity of a given power plant and correlates to its physical footprint on the landscape. Energy production measures the electricity generated per hour and correlates with the amount of emissions produced or water consumed per MWh of production. Dependable capacity is the metric used by energy resource planners to denote the amount of capacity available for dispatch during periods of peak demand.

Nameplate capacity as a percentage of the state's resource mix does not always correlate with electricity generation. Technologies like hydropower and wind have much lower dependable capacity ratings than baseload fuel types like nuclear and natural gas. These technologies are also known as "intermittent resources" because their production varies with nature's weather cycles. For example, the 13,286 MW of hydropower comprises 20 percent of total capacity, but its energy production can range from 9 to over 30 percent of in-state generation, depending on the amount of snowfall. The dependable capacity rating for wind is about 25 percent of the installed capacity figure. In contrast, California's 4,506 MW of nuclear capacity represent 7 percent of total nameplate capacity, but produce on average 13 percent of total generation because they operate in a continuous baseload duty cycle.

Since the *2005 Environmental Performance Report* (which reported 2003 data), California's total installed in-state capacity has increased from 61,462 MW to 66,797 MW (through the end of 2006). This increase is due to the addition of about 5,000 MW in natural gas-fired power plants – about 2,000 MW in new combined cycle and over 3,000 MW in combustion turbine peakers – plus an additional 500 MW of wind. Because wind power is expected to form a key part of the renewables development needed to meet RPS goals, the 2007 wind capacity figure of 2,202 MW is reported.

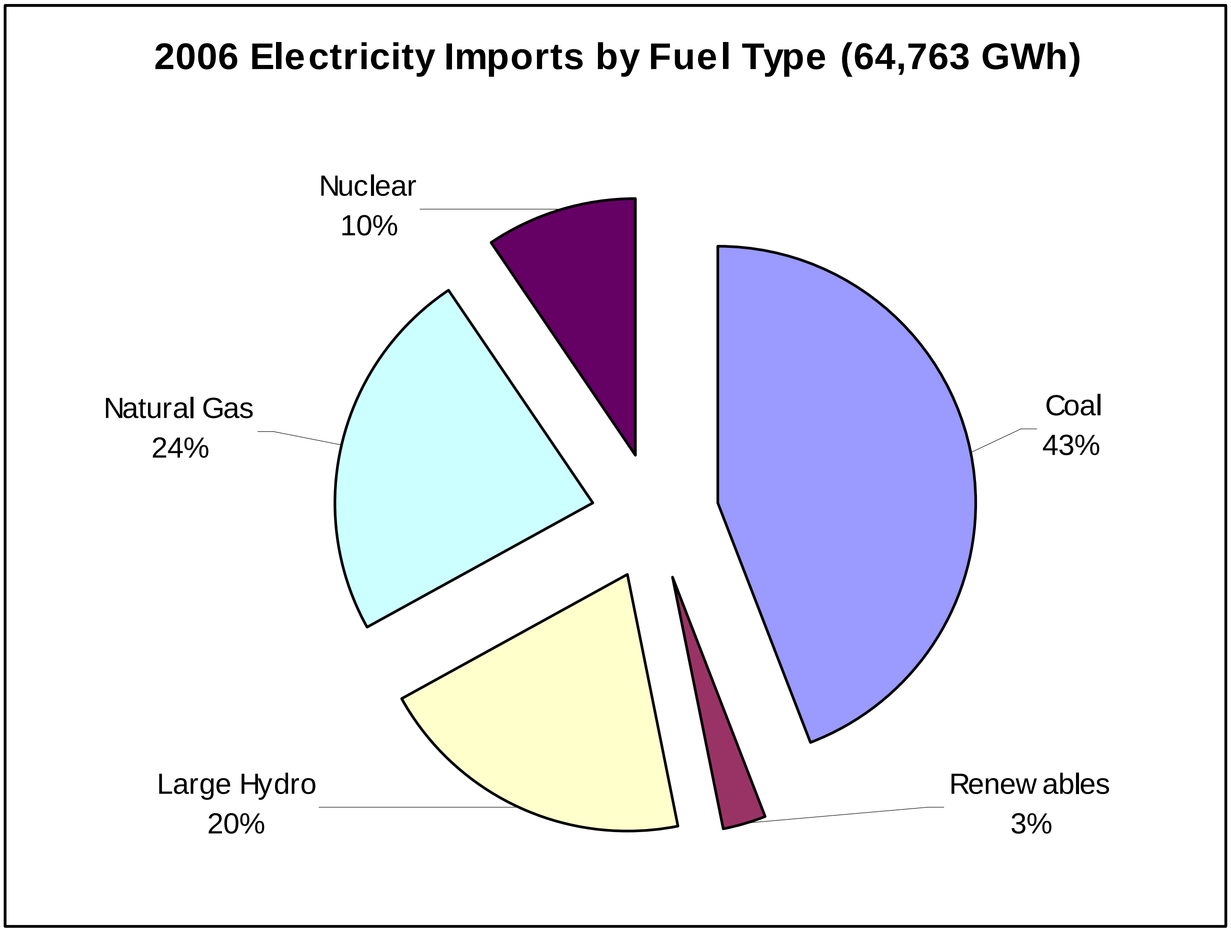
Figure 1: 2006 California Electricity Production by Fuel Type



* Disagregation of Imported Electricity by Fuel Type Shown in Figure 2

Source: Energy Commission 2006 Gross System Power Report

Figure 2: 2006 Electricity Imports by Fuel Type



Source: Energy Commission 2006 Gross System Power Report

Table 1: California 2006 In-State Nameplate Generating Capacity (MW) by Fuel Type and Technology (Total 66,797 MW)

Generation Technology	Natural Gas	Coal	Oil	Nuclear	Hydro	Biomass*	Geo-thermal*	Solar*	Wind**	Other	Total Capacity (Technology)
Cogeneration	6,884	552				387					939
Combined Cycle	10,275	24				35					10,334
Combustion Turbine	6,592		165			25					6,782
Large Hydro					12,042						12,042
Small Hydro* (<30 MW)					1,284						1,284
Internal Combustion	140		38			104					282
Photovoltaic***								2			2
Steam Turbine	17,910			4,506		521	2,684	378		45	26,045
Wind Turbine									2,202		2,202
Total Capacity (Fuel Type)	**41,801**	**576**	**203**	**4,506**	**13,326**	**1,073**	**2,684**	**380**	**2,202**	**45**	**66,797**

Notes: In-State Nameplate Generating Capacity represents the nameplate capacity used to generate electricity sold to the grid. It does not include the self-generation typical of cogeneration operations, nor generation on the customer side of the meter, which includes most solar PV. For EPR reporting purposes, coal capacity is only reported for the generating units located within California. This is in contrast to the generation figures, where out-of-state coal units owned by California utilities are reported as in-state generation.

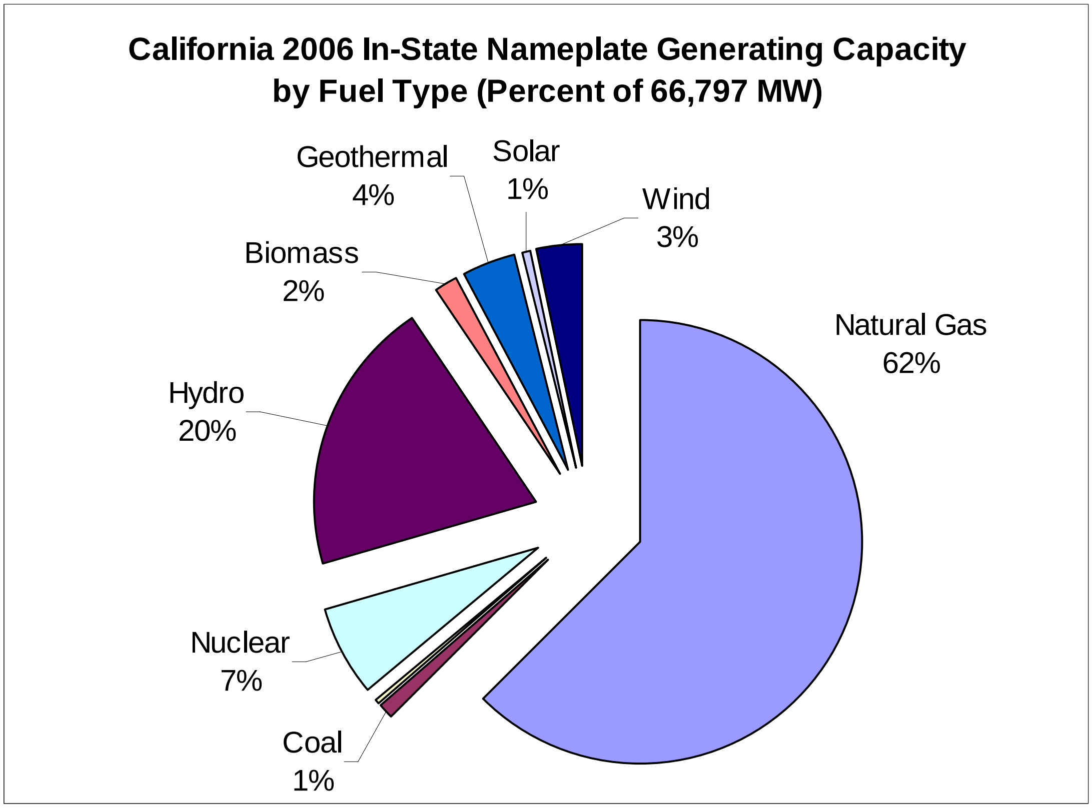
* RPS-eligible renewables. Total RPS-eligible renewable capacity = 7,623 MW

**Wind capacity data are current through July 2007.

*** Solar PV capacity figure used in Table 1 does not include the approximately 200 MW of solar PV that has been installed on the customer side of the meter.

Sources: California Energy Commission Quarterly Fuels Energy Report (QFER) Database and PIER Wind Resource Database.

Figure 3: California 2006 In-State Nameplate Generating Capacity by Fuel Type



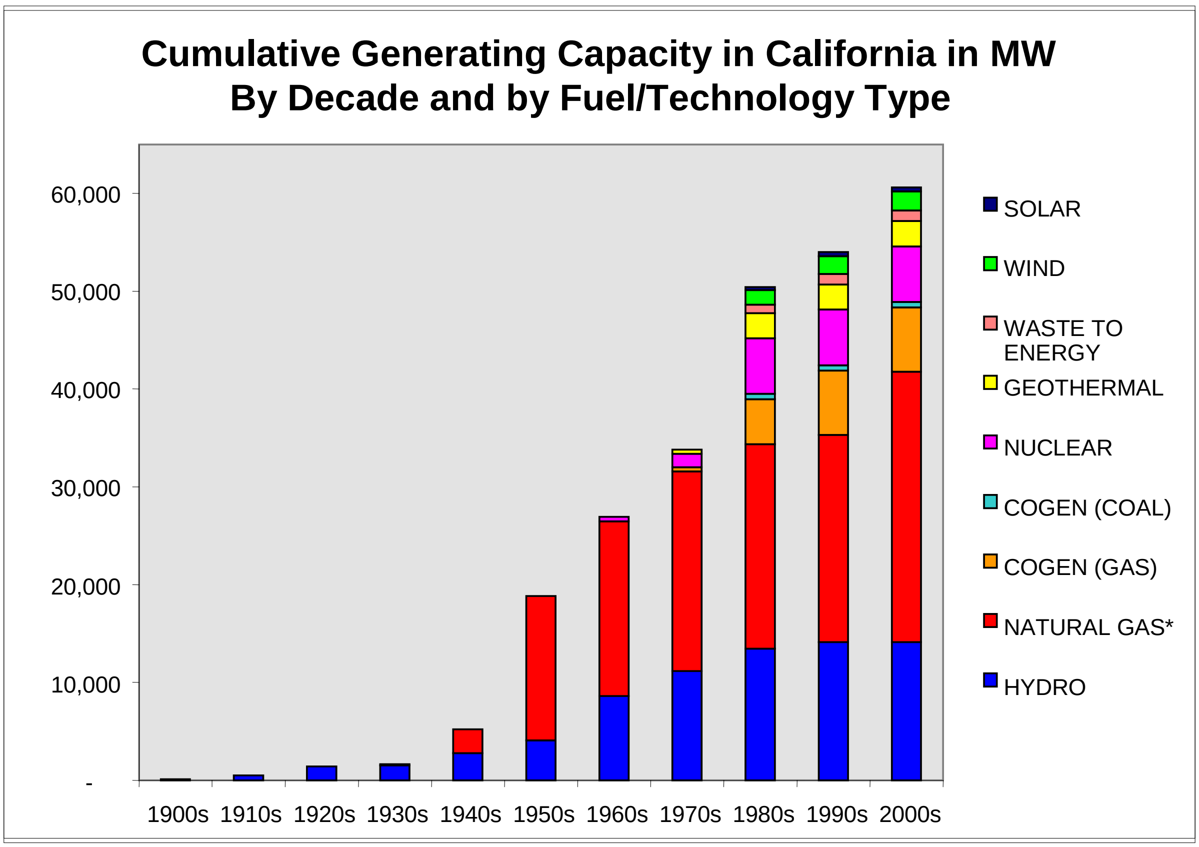
Source: Table 1

Evolution of California's Electricity System

California's in-state generating capacity is a function of geography, technology, and history. For the first half of the 20th century, large hydropower comprised the majority of the state' generating capacity, as early power companies tapped the tremendous hydropower potential of the Sierra Nevada and Southern Cascade mountain ranges. A great deal of the existing hydropower infrastructure is between 50 and 100 years old. During California's economic boom of the post-World War II era, large baseload oil-fired steam boiler plants were built along the California coast to serve coastal population centers. Nearly 18,000 MW of this early steam boiler fleet is still operational. Coastal power plant sites allowed easy transport of fuel oil and the use of sea water for cooling. California utilities switched the oil-fired power plants to natural gas as the primary fuel in the 1970s to meet new air quality standards. Because hydropower generation varies so widely from year to year in California, redundant capacity was developed in the steam boiler fleet to ensure that sufficient capacity was available to meet electricity demand in dry water years.

Four nuclear plants were constructed in the 1970s and '80s, two of which are still operational (Diablo Canyon and San Onofre). Renewable power began to be developed at a utility scale in the 1970s and '80s, along with cogeneration power plants. Large combined cycle combustion-turbine gas-fired power plants began to appear in the early 1990s, but it was not until after electricity industry deregulation in 1998 that these highly efficient power plants began to be widely deployed. California now has about 7,700 MW of combined cycle capacity, and the Energy Commission continues to receive a steady stream of new license applications each year. More recently, large gas-fired combustion turbine peaking power plants are being proposed to meet the demand for capacity during peak load periods. Figure 4 shows the evolution of California's resource mix. Figure 5 shows the geographic distribution of California's power plant fleet by generating technology.

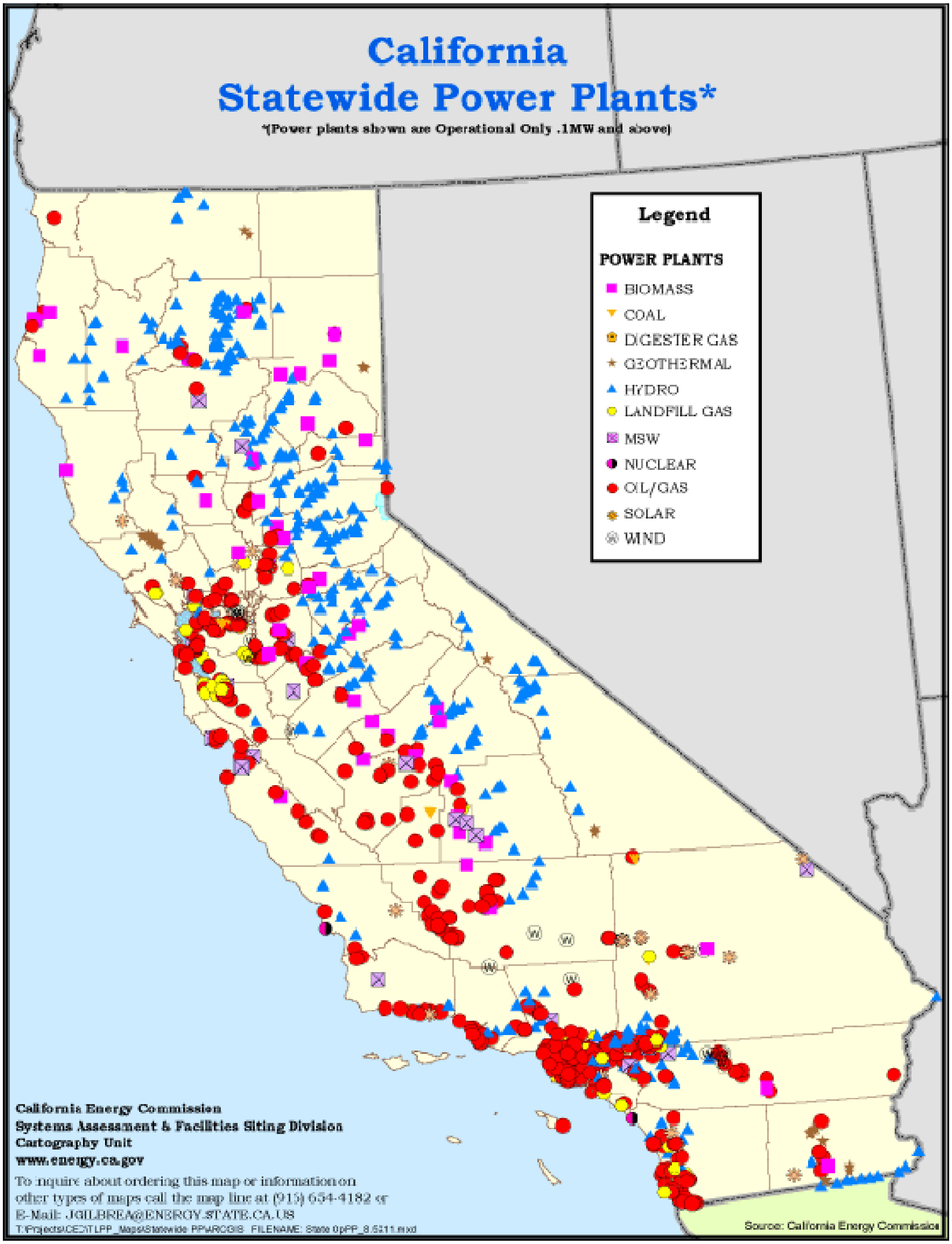
Figure 4: Cumulative Generating Capacity in California from the 1900's to 2000's by Fuel and Technology Type



*The original steam boiler fleet was fired by fuel oil. Air quality concerns and high fuel oil prices in the 1970's prompted a wholesale switch to natural gas.

Source: California Energy Commission QFER Database. Compiled by the Electricity Analysis Office

Figure 5: Geographic Distribution of California Power Plants by Generating Technology



Future Evolution of the Resource Mix

California merchant generators and public and private utilities will continue to develop new natural gas-fired generating resources and renewable resources and continue to make substantial investments to expand and reinforce the electric transmission grid. Retirement and repowering of aging gas-fired steam boilers, which began in the 1990s, is expected to continue. The *2005 Integrated Energy Policy Report* examined policy related to the remaining aging power plants in California and concluded that there has been less progress in the Southern California Edison planning area than in the rest of the state.

The policy framework for new energy resource development in California was first articulated in the *2003 Integrated Energy Policy Report*, and is now codified in the *Energy Action Plan* and *Loading Order*.[1] The Loading Order directs investor-owned utilities to meet increases in demand from 1) energy efficiency and demand response, 2) eligible renewable resources and distributed generation, and 3) clean and efficient fossil generation. The current Renewables Portfolio Standard (RPS) requires investor-owned utilities to derive 20 percent of their retail electric sales from renewable resources by 2010. The *2005 Integrated Energy Policy Report* and Governor Schwarzenegger have called for the RPS to be expanded to 33 percent of all power by 2020. Policy and regulatory standards to reduce power sector-related greenhouse gas emissions, such as AB 32, will also play a role in which types of generating resources are developed in the coming decades. Emerging environmental regulations will also shape future development, such as the pending proposed regulations from the State Water Resources Control Board to minimize once-through cooling impacts (see Chapter 3 – Once-Through Cooling) and the South Coast Air Quality Management District's recently adopted Priority Reserve Rule for emission reduction credits.

Renewables development is projected to expand greatly through 2020. As shown in Table 2, 2006 RPS-eligible renewables capacity totals 7,623 MW. Tables 2 and 3 summarize a series of possible renewables expansion levels by modeling or preliminary permit filings from different agencies, illustrating the potential for new renewables development in California. These levels of renewable energy development are illustrative and are intended to provide a sense of scale for the potential for renewables development in California, rather than specific long-term procurement plans.

The Energy Commission Public Interest Energy Research (PIER) Program's recent report on potential wind development in California models 20,680 MW of new wind resources in 2020 as part the analysis to assess how substantial new wind resources might affect the grid.[2] The California Independent System Operator (California ISO) tracks applications for grid interconnection studies from potential developers. The Interconnection Queue shows initial

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[1] *Energy Action Plan II: Implementation Roadmap for Energy Policies*, California Energy Commission and California Public Utilities Commission, September 21, 2005.

[2] Brower, M., (AWS Truewind, LLC). 2007. *Intermittency Analysis Project: Characterizing New Wind Resources in California.* California Energy Commission, PIER Renewable Energy Technologies. CEC ‑ 500 ‑ 2007 ‑ XXX.

interest from developers for nearly 30,000 MW in new renewables capacity. The Bureau of Land Management (BLM) maintains a database of Energy Applications from its five California Field Offices for energy projects on federal lands. BLM currently indicates applications for 38,498 MW in new renewables capacity for wind, solar thermal, and solar PV. Both the California ISO and BLM figures are likely to be at the high end of possible development through 2020; it is presumed that they overlap and should not be considered additive. The Energy Commission has licensing jurisdiction over geothermal, biomass, waste-to-energy and solar thermal projects with a capacity of 50 MW or greater. Twelve solar thermal projects totaling 4,070 MW are in various planning stages and have announced plans to file Applications for Certification at the Energy Commission. The High Renewables case from the Energy Commission's Scenario Modeling Project[3] shows that more aggressive development of renewables resources to about 33 percent could reduce electricity-related GHG emissions when coupled with an energy efficiency program. As modeled in this scenario, this would mean adding 16,244 MW of renewables capacity in four technology types by 202 to our current base of 7,623 MW.

Table 2: Existing Capacity and Potential Expansions in Renewables Capacity by Technology in California (MW)

		Projected In-State Renewables Additions (MW)				
Renewable Technology	**2005 Existing Capacity[1] (MW)**	**CEC Scenario Modeling Project[2]**	**CAISO Inter-Connection Queue[3]**	**PIER Intermittency Wind Analysis[4]**	**BLM Energy Applications[5]**	**CEC Licensing Program[6]**
Geothermal	2,684	2,415	95			
Solar Thermal	378	2,700	10,304		28,556	4,070
Solar PV	2	NA	3,152		9,334	NA
Wind	2,202	10,138	15,783	20,680	598	NA
Biomass*	1,070	991				
Small Hydro	1,284	0	0		0	NA
Totals	**7,620**	**16,244**	**29,801**	**20,680**	**38,498**	**4,070**

* Includes waste-to-energy

Sources: [1] Energy Commission QFER Database and Wind Energy Database

[2] Table 2-5, "Resource Additions to Satisfy a High Renewables Mix by 2020," Energy Commission Staff Draft Scenario Analysis Report

[3] California ISO website http://www.caiso.com/14e9/14e9ddda1ebf0.pdf, August 2007

[4] PIER Intermittency Wind Analysis Project, Table 1, new additions through 2020

[5] BLM California Field Offices

[6] Energy Commission Project Tracking Database

[3] Cases 4a and 5a, *Scenario Analysis of California's Electricity System: Preliminary Results for the 2007 Integrated Energy Policy Report*, Staff Draft Report No. 200-2007-010-SD, June 2007.

New natural gas-fired combined-cycle and simple-cycle combustion turbine power plants will continue to be built in California to meet load growth and replace retiring generation infrastructure. In addition to the highly efficient combined-cycle power plants, recent advances in turbine technology, such as with the new types of 100 MW turbines, have increased thermal efficiency and lower emissions rates so that simple-cycle peakers can be built cost-effectively and used widely to meet peak demand.

Several new projects are noteworthy. The 563 MW Victorville 2 Hybrid Project in San Bernardino County is California's first combined-cycle solar thermal power project. It will feature a hybrid design that integrates the two combustion turbines and heat recovery steam generator with 50 MW of solar thermal capacity from about 250 acres of solar collecting troughs. A similar hybrid project has also been proposed by the city of Palmdale in northern Los Angeles County with plans for filing an AFC in 2008. BP/ARCO and Southern California Edison are teaming to develop the Clean Hydrogen Project, which would be California's first petroleum coke-fueled integrated gasification combined-cycle (IGCC) project with carbon capture and sequestration. The AFC is anticipated during 2008.

Table 3 shows power plants licensed by the Energy Commission since 1979 when the licensing program began, plants under construction, plants in licensing review, and planned power plants.

Table 3: Power Plants Licensed, in Licensing Review, or Planned for Licensing Review at the California Energy Commission Since 1979

Power Plant Generation Technology	Operational		Approved for / in Construction		In Licensing Review		Planned or Announced	
	No. of Plants	Total MW	No. of Plants	Total MW	No. of Plants	Total MW	No. of Plants	Total MW
Combined Cycle	22	10,942	12	8,477	7	4,672	8	4,185
Simple Cycle Peakers	20	2,235	4	483	9	3,017	9	761
Cogeneration	17	2,844	1	51	1	63	1	
Solar Thermal	3	390				50	12	4,070
Geothermal	9	892	2	235				
Reciprocating Engine					2	279		
Gas IGCC							1	500
Totals	**71**	**17,303**	**19**	**9,246**	**19**	**8,081**	**31**	**9,516**

Source: California Energy Commission Power Plant Licensing Program Status Report, http://www.energy.ca.gov/sitingcases/all_projects.html

Retirements

Power plants of all types are retired or replaced in California as new and more efficient generating technologies emerge. Power plants are also retired or repowered when they cannot economically meet modern environmental regulatory requirements, such as installation of selective catalytic reduction to reduce NOx emissions on fossil-fueled power plants, installation of fish ladders on hydropower dams to allow for fish passage, or the retrofitting or replacement of once-through cooling systems at coastal power plants to reduce impacts to marine ecosystems.

The large, gas-fired steam boiler power plants from the 1950s constitute the majority of those power plants that have been retired or repowered since the late 1990s. The *2005 Integrated Energy Policy Report* called for studies to plan for the retirement of the steam boilers by 2012; Energy Commission staff presented testimony to the California Public Utilities Commission on the same topic in 2007.

In the *2005 Environmental Performance Report*, Energy Commission staff documented the retirement of 3,817 MW of primarily gas-fired generation since 2001. Since the 2005 Report, 219 additional MW of capacity have been retired in California. Closure of the Mohave coal-fired generating station in late 2005 resulted in the retirement of 1,011 MW of capacity that is owned by Southern California utilities in Nevada.

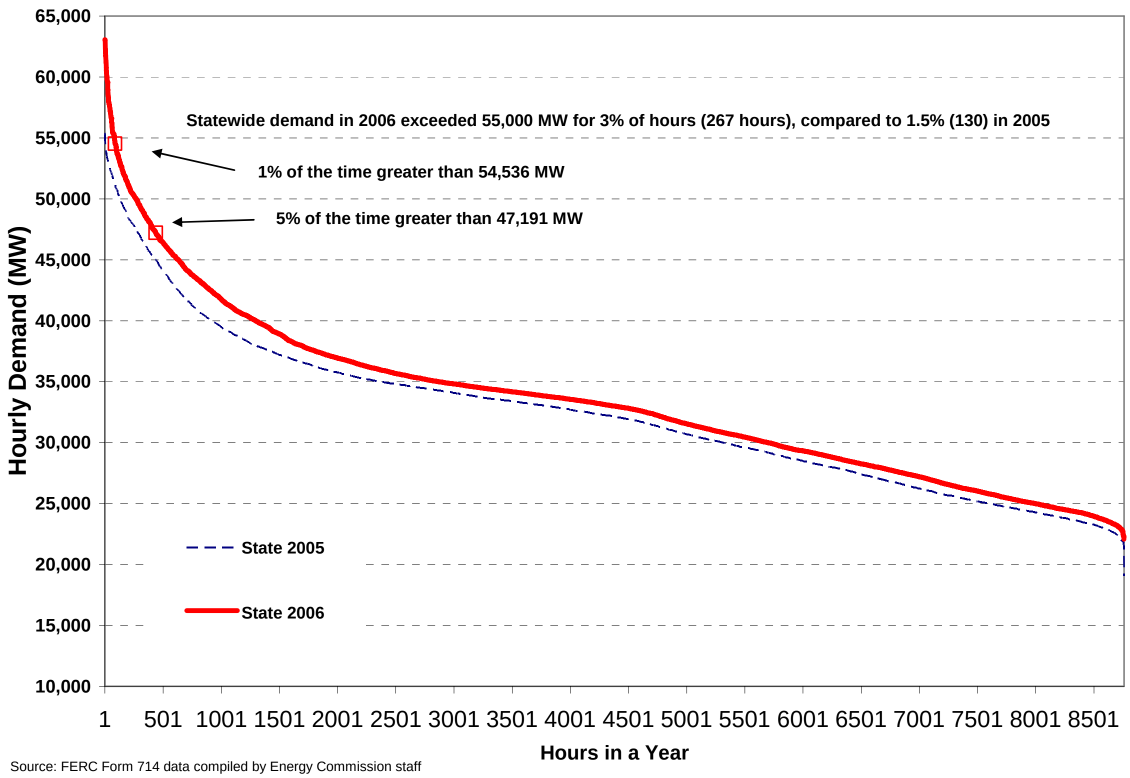
As discussed in more detail in Chapter 3, the Energy Commission has issued licenses or is reviewing license applications for a total of six large coastal power plant repowering, replacement, or expansion projects where most or all of the steam boiler units will be retired and replaced (Moss Landing, Morro Bay, El Segundo, Humboldt, South Bay, Encina, and Gateway).

The initial generation of cogeneration and gas-fired combustion turbines from the 1980's now have relatively inefficient heat rates when compared to modern turbines, and may be retired and modernized through repowering. Similarly, the initial vintage wind turbines from the 1970's and 1980's are slowly being retired and replaced with larger, more efficient turbines. Some hydropower projects in relicensing review at the Federal Energy Regulatory Commission are also candidates for decommissioning due to environmental concerns, such as the Klamath Hydro Project profiled in Chapter 6.

Generation, Operations, and Dispatch

The operating profile of California's diverse power generation system is governed by two basic factors; hourly electricity demand and generating technology. The demand for electricity in California is very peaky. In other words, demand for electric power varies widely by season and time of day. In summer, hourly peak demand can increase from 30,000 MW or so to more than 60,000 MW during hot weekday afternoons when air conditioning loads are high. However, as shown on Figure 6, peak demand may only last for a few critical hours each day on hot summer days. The statewide load duration curve shows that demand exceeds 54,536 MW 1 percent of the hours in a year (87.8 hours), and exceeds 47,191 MW 5 percent of the hours in a year (439 hours).

Figure 6: California's Statewide Load Duration Curve for 2005 and 2006



Source: FERC Form 714 data compiled by Energy Commission Staff

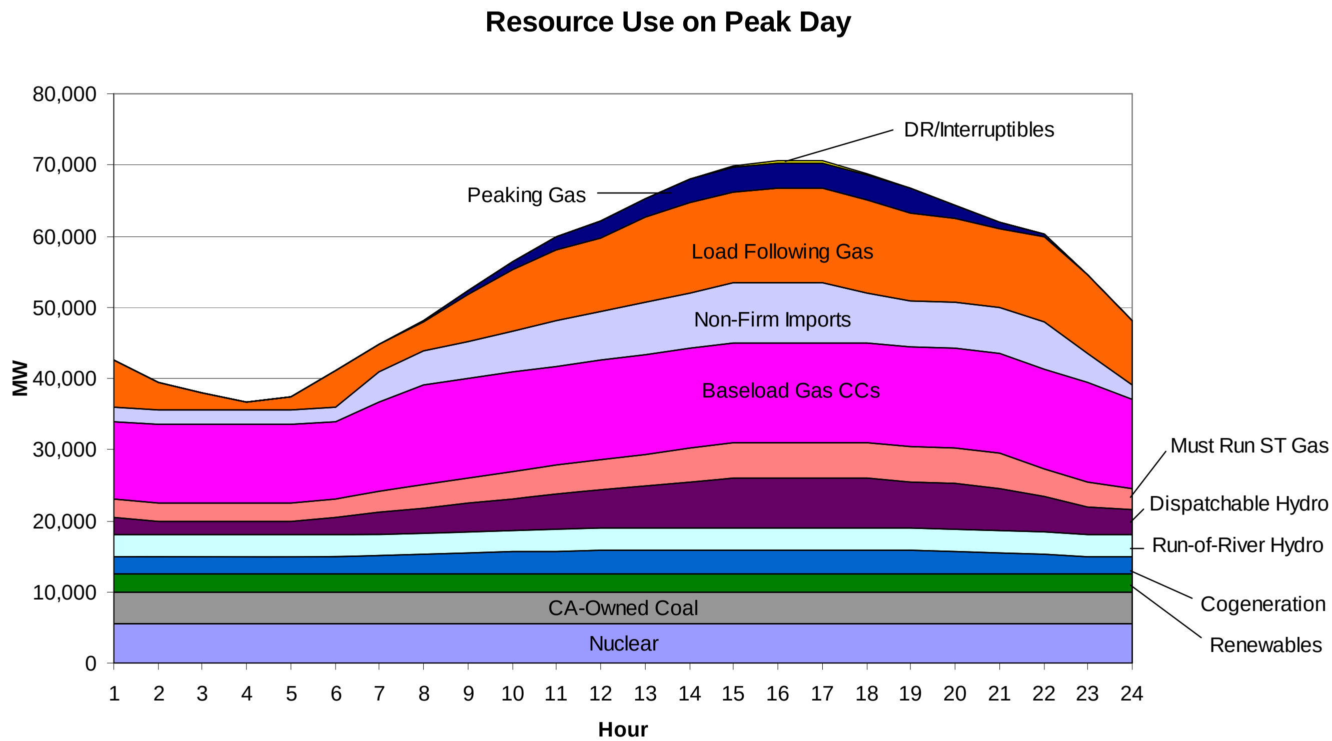
This basic tenet for electricity demand means that the California power generation fleet has a mix of generating resources that range from near full-time operation to operation of just a few days in a year, with a wide range in between. Figure 7 shows this range in operations for each type of generating resources on a typical peak demand day.

The term "duty cycle" describes how a power plant is dispatched or operated to meet fluctuating electric loads. A plant's duty cycle is a function of its technology and market demands for power. The basic types of duty cycles are:

- Baseload
- Load Following
- Intermittent
- Peaking

Baseload operation means that a power plant runs continuously at or near full capacity, unless down for maintenance or refueling. Nuclear, coal, geothermal, cogeneration, biomass and waste-to-energy power plants typically operate in baseload mode. Although gas-fired steam boilers and combined cycle power plants were originally designed to run in baseload mode, many are currently used in load following mode or for local reliability.

Figure 7: Typical Peak Day Generating Resources



Source: California Energy Commission

Load-following operation means that a power plant is operated at varying output levels to meet the daily changes in load. Hydropower has traditionally been the classic load-following technology because it can be ramped up and down very quickly. Gas-fired combined cycle and steam boiler power plants now form the bulk of the load following resources in California, even though they were designed as baseload power plants.

Intermittent operation means that a power plant is operated according to the availability of the underlying fuel resource. Primary examples include renewable resources such as wind, solar and small hydro, and large hydro (which is not an RPS-eligible renewable). Many of these power plants are also “must take” resources because LSEs have a contractual obligation to buy and use their power as available.

The peaking duty cycle denotes the power plants called upon just to meet peak demands a few hours or days a year. Hydropower was the traditional peaking resource, but new gas-fired combustion turbine units are now forming the bulk of peaking reserves. The vintage steam boiler power plants from the 1950s and 1960s are now used in a peaking mode as reserve capacity, even though they were designed and run as baseload units for decades.[4]

The California ISO is responsible for matching generation to load within its control area, and has authority to dispatch generating resources across California and the Western United States. The other main control areas are for the big municipal utilities, such as the Los Angeles Department of Water and Power, and the Sacramento Municipal Utility District. The federal government also controls large amounts of generating resources, primarily from the large federal hydro projects in California and the Pacific Northwest.

The Role of Imports in Meeting California's Electricity Demand

Imported power plays a critical role in meeting California electricity demands and resource adequacy goals. Imports comprise from 20 to 30 percent of total in-state electricity sales, depending on weather and available hydro capacity.

Understanding and tracking power imports is complex. To begin with, California utilities own large shares of out-of-state coal and nuclear power plants. Some of this California-owned power is classified as "in-state" generation for supply-demand balance reporting purposes, while some is classified as imported power. As reported in the *2005 Environmental Performance Report* white paper on power imports,[5] California utilities owned shares in 6,200 MW of out-of-state resources, including 4,744 MW of coal (also known as "dedicated coal"), and 1,062 MW of nuclear from the 3,875 MW Palo Verde Nuclear Station in Arizona. With the closure of the Mohave Generating Station coal plant, California utilities now own 4,956 MW of out-of-state resources, 3,500 MW of which is coal. Table 4 shows current California ownership in out-of-state coal-fired power plants.

The Department of Water Resources (DWR) acquired its partial ownership share of the Reid Gardner coal plant in Nevada in 1979. The State Water Project is the single largest user of electric power in California, and DWR required an affordable and dependable source of electricity. However, DWR recently announced plans to withdraw from the Reid Gardner plant.

"DWR has announced that to reduce greenhouse gas emissions and meet the goals of AB 32, the Global Warming Solutions Act, it will not extend its interest in Reid Gardner when it expires in 2013. This will allow DWR to meet AB 32 goals in advance of the 2020 deadline. We are exploring power options that are both reliable and cost-effective."[6]

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[4] The steam boiler power plants now used for load following and peaking reserves typically do not shut down entirely during periods of low demand. To maintain boiler pressure and be available for dispatch when needed, they are operated in a standby mode or produce minimal amounts of power.

[5] *A Preliminary Environmental Profile of California's Imported Electricity*, Energy Commission Staff Report Prepared in Support of the *2005 Integrated Energy Policy Report*, Report No. 700-2005-017, June 2005.

[6] Letter to the Editor of the *Sacramento Bee* from Lester Snow, Director of the Department of Water Resources, June 26, 2007.

Energy from the dedicated out-of-state resources is supplemented each year by additional imports from the Pacific Northwest and Southwest. Resources from the northwest are predominantly large hydro generation from the Bonneville Power Administration, and coal and natural gas generation from merchant generators. Southwest imports are predominately coal, natural gas and nuclear. Electricity import levels vary in relation to California weather, which drives air conditioning loads in the summer, and Western hydro reserves, which vary by snowpack and water year-type in the West and Northwest.

Table 4: 2007 California Utility Ownership in Out-Of-State Coal Power Plants

Plant Name	Operating Company	Total Nameplate Capacity	Generating Unit	Unit-level Capacity	California Ownership	CA Percent Owned	CA MW Owned
Arizona							
Navajo Generating Station	Salt River Project Ag. I & P Co.	2,409 MW	NAV1	803.1	Los Angeles Dept Water & Power	21.2	170
			NAV2	803.1	Los Angeles Dept Water & Power	21.2	170
			NAV3	803.1	Los Angeles Dept Water & Power	21.2	170
Nevada							
Reid Gardner Generating Plant	Nevada Power Company	612 MW	4	270	California Dept of Water Resources	67.8	183
Mohave Generating Station **RETIRED**	The 1,580 MW Mohave Generating Station was closed in December 2005 due to costs associated with installing new pollution control equipment and inability to secure water rights to continue using the coal slurry supply pipeline. Southern California Edison owned a 853 MW share of Mohave, and LADWP owned 158 MW.						
New Mexico							
Four Corners Power Plant	Arizona Public Service Company	2,070 MW	4	818.1	Southern California Edison Co	48	393
			5	818.1	Southern California Edison Co	48	393
San Juan Generating Station	Public Service Company of New Mexico	1,848 MW	3	555	City of Azusa	6.15	34
			3	555	City of Colton	6.15	34
			3	555	City of Glendale	4.1	23
			3	555	City of Banning	4.1	23
			3	555	Imperial Irrigation District	21.3	118
			4	555	City of Anaheim	10.04	56
			4	555	MSR Public Power Agency	28.71	159
Utah							
Intermountain Power Plant	Los Angeles Department of Water and Power	1,640 MW	1	900	Intermountain Power Agency*	96	787
			2	855	Intermountain Power Agency*	96	787
Total Out-of-State Coal-Fired Resources Owned by California Utilities: 3,500 MW							

Source: Modified from Table 3-2 in the *2005 Environmental Performance Report paper, Preliminary Environmental Profile of California's Electricity Imports* with updated information from the Electricity Analysis Office. Original data from U.S. Energy Information Agency website.

* California companies own entitlements to 96 percent of the generation from the Intermountain Power Agency.

Table 5 shows total electricity generation and consumption in California for in-state and imported power. For 2006, which saw above-average hydro conditions in California, coal from the dedicated ownership plants and additional imports comprised a total of 15.7 percent of all electricity consumed. The combination of an above-average hydro year and the closure of the Mohave Generating Station reduced the total amount of coal-fired generation used in California from the 20 percent level in 2005. A total of 12,951 GWh of hydroelectricity were imported from the Pacific Northwest and Colorado River. Nuclear power imports from the Southwest – primarily from the Palo Verde Nuclear Station operated by Arizona Public Service, but partially owned by California utilities – totaled 5,635 GWh in 2006. An increasingly large share of the resource mix for imports is coming from new, merchant, natural gas-fired power plants in the Southwest. In 2006, about 13,200 GWh of gas-fired generation was imported.

Table 5: 2006 Gross System Power – Total In-State and Imported Generation of 294,865 GWh

Fuel Type	In-State	North West Imports	South West Imports	GSP	GSP %
Coal[1]	17,573	5,467	23,195	**46,235**	**15.7%**
Large Hydro	43,088	10,608	2,343	**56,039**	**19.0%**
Natural Gas	106,968	2,051	13,207	**122,226**	**41.5%**
Nuclear	31,959	556	5,635	**38,150**	**12.9%**
Renewables	30,514	1,122	579	**32,215**	**10.9%**
Biomass	5,735	430	120	**6,285**	**2.1%**
Geothermal	13,448	0	260	**13,708**	**4.7%**
Small Hydro	5,788	448	0	**6,236**	**2.1%**
Solar	616	0	0	**616**	**0.2%**
Wind	4,927	244	199	**5,370**	**1.8%**
Total	230,102	19,804	44,959	**294,865**	**100%**

[1] "In-State Coal" includes electricity from out-of-state coal plants owned by California utilities

Source: *2006 Gross System Power*, California Energy Commission Website, http://www.energy.ca.gov/electricity/gross_system_power.html

Accurately tracking and understanding power imports is becoming increasingly important in the context of concerns about climate change because of state policy goals to reduce greenhouse gas emissions from the electricity sector.

The Gross System Power report is used by the Energy Commission to identify all electricity generated in-state or imported to California and delineate it by fuel type. While the generation source of much of this power is specified by contracts, ownership shares, or other means, there is presently no western-wide system that identifies every generation source that is imported to California. The method used to calculate the imported portion of Gross System Power in the Net System Power Report is called the "mix average methodology" and assumes that the resource mix of imported power from each region is proportional to the average resource mix in that region. The information in Table 5 is derived using the "mix average methodology."

New Method to Assess Electricity Imports

Since AB 32 has become law, it is important to accurately set a historic 1990 baseline for greenhouse gas emissions and measure progress toward California's greenhouse gas reduction requirements. This requires accurate calculation of the resource mix and resulting greenhouse gas emissions of the state's electricity system across time.

The Energy Commission staff initiated proceedings to reevaluate the assumptions used to calculate the resource mix of imports. In May 2006, staff published a draft research paper proposing an alternate method of calculating imports called the regional marginal resource (marginal) methodology. This methodology[7] identifies all specified imports and assumes that the resource mix of the unspecified portion for each region should be based on modeling of the generation dispatched in the region as a result of power sales to serve California's load, not on the average mix of the region. This research paper was reviewed in a Commission Committee workshop and staff was directed to conduct further studies.

In the California Public Utilities Commission – California Energy Commission Joint proceeding to implement AB 32, staff presented a follow-up draft research paper in March 2007, which provided revisions to the proposed methodology.[8] These methods, and others proposed by parties were considered in workshops and formal comments.

To date, parties have not resolved the superior analytic approach to calculating the correct mix of natural gas, hydro and coal that are imported into California. Since coal has roughly twice the carbon emissions of an equivalent kilowatt hour generated by natural gas, the resource mix has a disproportionate impact on the overall carbon content of California's GHG emissions.

The Energy Commission and the California Public Utilities Commission have initiated joint proceeding to develop methods and a reporting protocol to determine the greenhouse gas emissions of retail electricity providers. In September, the Commissions decided that further work and coordination with other western states is necessary before an import emissions characterization can be established. In the interim, a uniform default emissions rate of 1,100 pounds of CO_2 per MWh will be used for all unspecified purchases.

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[7] "Proposed Methodology to Estimate the Generation Resource Mix of California Electricity Imports," Staff Paper, Alvarado, May 2006, CEC-700-2006-007.

[8] "Revised Methodology to Estimate the Generation Resource Mix of California Electricity Imports," Staff Paper, Alvarado and Griffin, March 2007, CEC-700-2007.

CHAPTER 3: Cooling Water Use at New Power Plants Subject to Energy Commission Jurisdiction

Introduction and Policy Overview

This chapter provides an overview of statewide water use and polices and then examines cooling water use at new power plants licensed by the California Energy Commission to assess the effectiveness of the 2003 Cooling Water Policy.

A central theme in California's history is the endeavor to secure sufficient water supplies to meet the needs of the state's ever-growing population and economy. The state's population totaled 37.4 million in 2006 – up 14.6 percent from 1996 – and is expected to grow to 48 million by 2030. Historically, the natural constraints in California's climate and hydrology have been overcome through vast state and federal public works projects that can store and convey the more abundant water resources from Northern California and the Colorado River to the arid southern part of the state where the bulk of the population and economic growth continue to occur.

California's basic hydrologic cycles vary widely in terms of total annual precipitation and snowfall. Hydrology can also vary geographically within a given water year; for example, the relative decrease in snowfall in the Southern Sierra may be more pronounced in a dry year than in the Northern Sierra. As the effects of global climate change take effect in North America, the current annual and geographic variances in total precipitation and snowpack are projected to become more extreme and create new constraints and challenges for meeting the growth in demand for water.

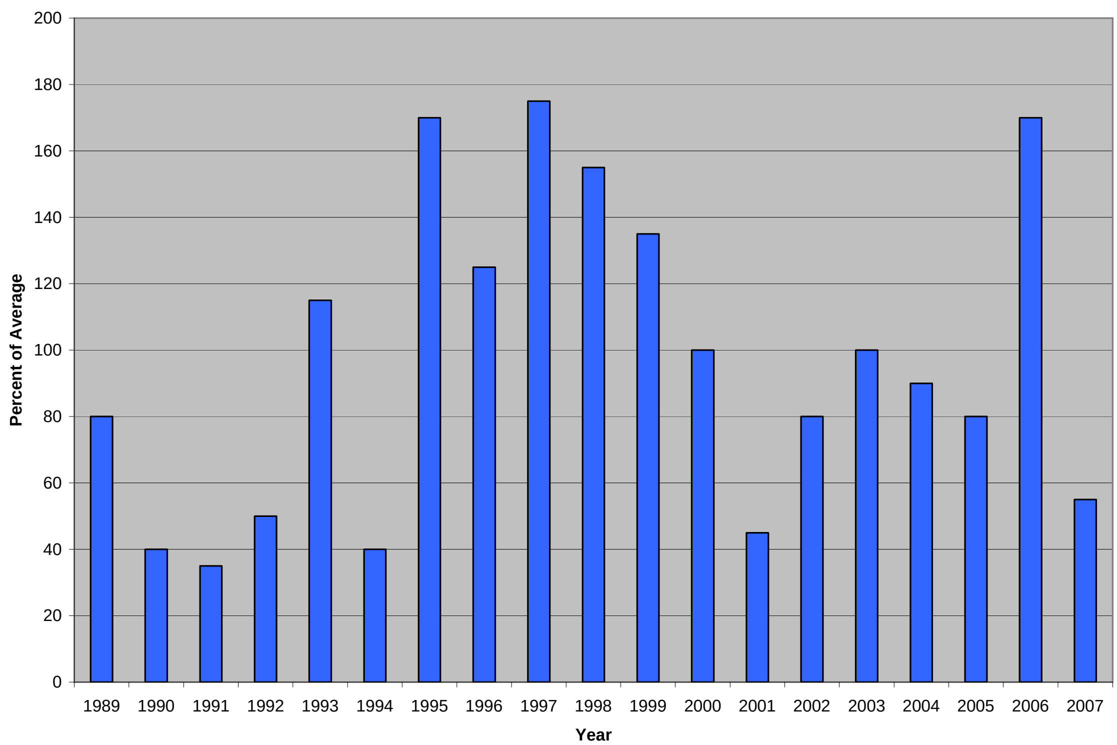
As described by the Department of Water Resources in its *2005 Water Plan Update*, [9] new strategies are being used to meet the competing demands for industrial, municipal, agricultural, and environmental water. Increasing the efficiency of water use and reducing per capita demand, developing recycled water supplies, re-allocating water from agriculture to municipal and environmental purposes, and investigating desalinization of ocean and brackish water are becoming the preferred strategies for ensuring sufficient water supplies for human and economic demands.

[9] 2005 Water Plan Update, Volume 3, Chapter 1, Table 1-2, California Department of Water Resources.

How California Uses Water

In a normal water year (measured from October 1 to September 30), California's total water supplies from precipitation, snowpack runoff and imports are about 200 million-acre feet (maf). Typical variance in state water supplies range from wet years producing 337 maf (171 percent of normal) to dry years producing 146 maf (72 percent of normal), with more extreme conditions having occurred historically and expected in the future. Figure 7 illustrates the variance in total unimpaired run-off (precipitation plus snowmelt) as the percentage of the long-term "normal average" from 1989 to 2007.

Figure 8: Total Unimpaired Run-Off in California Percent of Normal: 1989 – 2007



Source: DWR Bulletin 120

The Water Plan categorizes the 83 million acres-feet (MAF) of "dedicated water" in an average water year by the three basic uses shown in Table 6 ("dedicated water" denotes water with property rights or legal definitions). The balance of the 194 MAF not classified as "dedicated" evapotranspirates through native vegetation, evaporates, or flows ultimately to the ocean, inland lakes, or groundwater basins. Urban uses of water are further disaggregated as shown in Table 7.

Table 6: Allocations of Dedicated Water Use as Described in the 2005 Water Plan

	Average Year Amount	
Dedicated Water Use	**Volume (MAF)**	**Percent**
Urban Uses	8.9	11
Agricultural Uses	34.2	41
Environmental Water	39.4	48
Total Dedicated Supply	82.5	100

Source: 2005 Water Plan, Table 1-1.

Table 7: Urban Uses of Water as Described in the 2005 Water Plan

	Average Year Amount	
Urban Use Category	Volume (MAF)	Percent
Energy Production	0.1	1.1
Industrial	0.6	6.7
Large Landscape	0.7	7.8
Commercial	1.6	17.9
Residential	5.6	62.9
Conveyance Loss	0.2	2.2
Groundwater Recharge	0.1	1.1
Total Dedicated Urban Use	8.9	

Source: 2005 Water Plan, Table 1-3.

Although at first glance energy production is currently understood to require proportionately less water compared to other urban uses in the state, if 50 percent of energy production-related use could be conserved, water could be made available from existing supplies to serve a population of about 250,000.

2007 Water Year Illustrates Competing Human and Ecological Water Demands

While the 2006 water year was one of the wettest in recent history, the 2007 water year was a dry year with limited precipitation and snowfall throughout the state. According to the National Weather Service records, annual rainfall from July 1, 2006, to June 30, 2007, showed that most of California had significantly below-normal precipitation and that downtown Los Angeles experienced its driest year of record. Average snowpack throughout the Sierra Nevada was 29 percent of normal. The greater San Joaquin Basin watershed was classified as a "critical dry year," while the greater Sacramento Basin watershed was classified as a "dry year."

Dry water years such as occurred in 2007 place enormous stresses on freshwater ecosystems in California rivers and in the San Francisco Bay-Delta Estuary. Many of these ecosystems are already stressed in normal water years, as evidenced by the large numbers of endangered fish species in the rivers and estuaries. Dry water years create competing demands among human, agricultural, and industrial uses for water and the state's freshwater ecosystems. While the state and federal water projects help ensure a relatively steady supply of water for human uses, water flows in rivers and through the Bay-Delta tend to be reduced significantly.

One example of the competing demands for water in dry water years occurred in June and July of 2007 in the San Francisco Bay-Delta. Low levels of river outflows from the primary tributaries to the Sacramento and San Joaquin Rivers left the endangered Delta smelt – a three inch-long fish once widely distributed in the Bay-Delta – holding near the State Water Project pumps in the Southern Delta rather than moving westward toward the Bay as they do in normal water years. The smelts' presence meant that DWR had to curtail pumping water to agricultural and urban customers in Central and Southern California to avoid entraining and killing large numbers of the endangered fish. "Drastic times call for drastic measures" was how DWR Director Lester Snow referred to the unprecedented curtailment in State Water Project pumping.[10] The U.S. Bureau of Reclamation also substantially reduced pumping levels for nearly two months to help protect the Delta smelt. A federal District Court judge ruled in August that water supply and fisheries agencies needed to do more to protect the Delta smelt.

On the Sacramento River, the Bureau of Reclamation changed operation of its diversion gates at the Red Bluff Diversion Dam to account for the very low water levels and inadvertently trapped and killed several mature, spawning-age green sturgeon, which is listed as "threatened" under the federal Endangered Species Act. The Department of Fish and Game estimated that as few as 50 spawning age green sturgeon remain in the Sacramento River.[11]

Energy Commission 2003 Water Policy

In the *2003 Integrated Energy Policy Report*, the Energy Commission adopted a new policy on cooling water use for power plants subject to its licensing jurisdiction.

"Consistent with the [State Water Resources Control] Board policy and the Warren-Alquist Act, the Energy Commission will approve the use of fresh water for cooling purposes by power plants which it licenses only where alternative water supply sources and alternative cooling technologies are shown to be 'environmentally undesirable'" or 'economically unsound.' …"

The Energy Commission interprets "environmentally undesirable" to mean the same as having a "significant adverse environmental impact" and "economically unsound" to mean the same as "economically or otherwise infeasible."

This policy was adopted in response to the predominant use of fresh, inland surface water and groundwater for power plant cooling in the first five years of energy market deregulation when

[10] Department of Water Resources News Release, May 31, 2007.
[11] "Sturgeon Crushed by Water Gates," Sacramento Bee, June 25, 2007.

merchant power companies began developing the current fleet of private, combined-cycle and simple-cycle power plants in California. Although the 0.1 million acre-feet of water consumed annually for energy production is a tiny portion of the 8.9 MAF used each year for all municipal, industrial, and commercial uses, a large power plant or cluster of power plants can adversely impact fresh water resources in local water basins where municipal and industrial uses can exceed available water supplies. The entire Central and Southern Coasts of California have limited fresh water resources, as do all of the interior regions of Southern California. Because these same regions have many of the fastest growing populations and local economies in the state, power plant developers often propose new power plants there to serve the growth in electrical load.

The following sections of this chapter show the trends in power plant cooling following the Commission's adoption of its new Water Policy in 2003.

Cooling Water Trends for California Power Plants

The developmental history of California's power generation infrastructure is a function of geography and technology. In the first half of the 20th century, most of the central station power came from the vast hydroelectric resources of the Sierra Nevada. In the economic boom years of World War II and after, large central station steam boiler power plants were constructed primarily on the coast or the banks of the San Francisco Estuary. Coastal sites allowed for easy access to fuel oil docks and to cold ocean water that could be easily used for power plant cooling using the once-through cooling technology. Currently, about 30 percent of California's fossil and nuclear-fueled power generation fleet (21,250 MW on a nameplate capacity basis) still relies on sea water and once-through cooling technologies. The Diablo Canyon and San Onofre nuclear power plants also use seawater. The large inland power plants in the Los Angeles Basin generally use fresh or reclaimed water in wet cooling towers for steam cycle cooling.

Most of the existing power plants in California require water for cooling, including the natural gas, coal, nuclear, biomass, geothermal and solar thermal generating technologies. Wind, solar photovoltaic, and hydropower facilities do not require cooling water. Some recently developed combined-cycle, simple-cycle, and internal combustion power plants are now using air-cooling technologies, but this is still just a small part of the total power generation fleet.

California has about 1,000 power plants one MW or greater in size. As shown on Table 8, Energy Commission staff estimates that approximately 283 power plants 20 MW or greater in size use water for cooling. These power plants that use cooling water can be divided into 3 main categories, the older steam boilers, the new combined-cycle combustion turbines, and the simple-cycle turbines used for peaking. In order to assess trends in actual water use on a normalized (gallons per MWh) basis or in aggregate (total gallons or acre-feet per year), Energy Commission staff would need both operating data and water use data for each power plant. Such water use data are not readily available. Therefore, the analysis on trends in cooling water use presented later in this chapter examines only power plants subject to Energy Commission jurisdiction licensed since 1996. It does not include the fleet of steam boilers built well before the

Energy Commission was established in 1974, or power plants less than 50 MW in size, or repowering projects with less than a 50 MW net increase in generating capacity, such as the Los Angeles Department of Water and Power's recent repower of several units at the 1,600 MW Haynes Generating Station.

In 2007, the Energy Commission adopted new regulations that will allow staff to collect data on water use from power plant owners.[12] This new regulation will enable the Energy Commission to fill the gaps in staff's knowledge of how power plants use water in California. Staff plans to develop Forms and Instructions for the data collection as part of the 2009 IEPR cycle.

The new regulations will require owners of all power plants 20 MW or greater that use cooling water to provide annual information on its cooling technology, the volume and source of its cooling water, and the metering technology. The new regulations will require similar information on wastewater discharges.

Table 8: Estimated Number of Power Plants in California > 20 MW Using Cooling Water

Generating Technology	Number of Plants > 20 MW
Biomass	34
Coal	17
Geothermal	42
Natural Gas	188
Nuclear	2
Solar Thermal	3
Total	**286**

Sources: Estimated from Energy Commission QFER Database, as reported to Office of Administrative Law during the Energy Commission Data Collection Rulemaking Proceeding 2007. However, the 3 solar thermal plants were inadvertently omitted from the OAL filing.

Note: Energy Commission staff assumed a 20 MW-threshold for power plants using cooling water.

[12] Data Collection Order Instituting Rulemaking Proceeding, Section 1304, California Energy Commission Docket No. 05-DATA-1, Adopted April 25, 2007.

How Power Plants Use Water

Power plants that use a thermal process to generate electricity require a cooling process to remove waste heat from the power production cycle. Water and air are the media traditionally used for cooling power plant steam condensers. Most power plants that use water employ either once-through cooling or evaporative cooling. In once-through cooling systems, large amounts of cold water from the ocean, estuaries, lakes, or rivers are circulated through the steam condenser a single time and the heated water is then discharged back to the source water (In California, only ocean and estuarine water is used in once-through cooling systems). Evaporative cooling uses a cooling tower to dissipate the excess heat through evaporation of a portion of the cooling water.

Air-cooled systems dissipate waste heat by convection, condensing the steam by circulating air with large fans past tubes conveying either the steam to be condensed or cooling water that has been used to condense that steam in a separate condenser. Combined cycle power plants using air cooling systems for steam condensation still require small amounts of water to replenish the steam cycle and for cooling the air flowing through the gas turbines.

Table 9 shows the relative amounts of cooling water typically used by thermal power plants currently operating in California based on data reported in 2005 to the Energy Commission from about half of the state's generators. The most common types of thermal processes in operation in California can be broken down into four broad categories: steam boilers, natural gas-fired turbines (simple-cycle or combined-cycle configurations), solar thermal energy, and geothermal energy. (Note that geothermal power plants use the geothermal fluid produced from the earth for cooling purposes.) Combined-cycle configurations when using air-cooled designs can realize large reductions in water consumption.

- **Steam Boilers** – Whether fired by natural gas, coal, nuclear fuel, geothermal heat, solar heat, or biomass fuels, these steam-cycle plants require small amounts of water to maintain appropriate levels and water chemistry in the boiler, and large quantities of cooling water (or air) to condense steam exhausted from the turbine.

- **Natural Gas-Fired Turbines** – Natural gas-fired turbines represent the most widely used power plant technology used to generate electricity in California. They are typically employed in two kinds of power plants: simple-cycle turbines, also called "peaking plants," and combined-cycle turbines.

- **Simple-Cycle Turbines (Peakers)** – Simple-cycle turbines are inherently air cooled; the air that passes through the machine carries away heat in the exhaust stream. Individual simple-cycle turbines used in California typically range from 45 MW to 100 MW. The power output and fuel efficiency of a gas turbine can be enhanced by cooling the air as it enters the turbine, also called "inlet cooling." The inlet air of these systems may be cooled using an evaporative cooling system or a fogging system or may be mechanically chilled without the use of water. (The heat rejected from the chiller, however, must be disposed of with a separate cooling system.) If water is used for inlet air cooling, the typical water requirement for plants with a 500 MW capacity is about 825 acre-feet per year (AFY).

- **Combined-Cycle Turbines** – Combined-cycle turbine systems are based on one or more simple-cycle gas turbines, whose exhaust heat is then employed in a heat recovery steam generator (HRSG) to produce additional electricity in a steam turbine generator. Combined-cycle systems are typically configured with a generating capacity of 250 MW or greater. These systems can also be optimized with inlet air cooling as are the simple-cycle turbines. In addition, combined-cycle power plants require cooling of steam as it leaves the steam turbine generator. This steam may be cooled using a traditional wet cooling tower configuration or using air-cooled systems that do not consume water. Typical water requirements for a 500 MW combined-cycle, wet cooling tower system can be 3,500 acre-feet (AF) or more per year. If an air-cooled system is employed, water consumption can be reduced an order of magnitude to 150 to 250 AFY, depending on the method for air flow cooling of the gas turbines.

- **Solar Thermal** – Solar thermal plants substitute solar energy for natural gas as the fuel source to convert water into steam. The solar energy is converted into steam in a steam boiler from which the steam powers a turbine. In addition, solar thermal plants require a small amount of relatively pure water for routine and annual mirror washing. The volumes of water vary depending on plant capacity, solar receiver type, and mirror surface area. Accordingly, water use varies considerably depending on the type of solar plant in operation. Solar thermal plants can also minimize use of water by using air-cooling.

- **Stirling Engines** – Stirling engines convert solar energy reflected from mirrors into thermal energy (heat) inside a self-contained 250 kilowatt engine. (Four Stirling engines would be needed to generate 1 MW). Because the engines are air-cooled, water is not used except for minimal use for mirror washing.

- **Geothermal Energy** – Geothermal power plants use naturally occurring hot water/steam to drive a steam turbine generator. After the steam has driven the turbine, it is condensed in the condenser and pumped to an evaporative cooling tower. Here, a portion of the water evaporates, cooling the remaining water. Some of this cooled water is pumped to the condenser to condense steam; the balance is available for reinjection into the ground.

Table 9: Typical Cooling Water Withdrawal and Consumption Rates For Operating Power Plants in California

Energy Resource, Plant Type, & Cooling System	Water Withdrawn for Cooling & Processes (gallons/MWhr)[1]	Water Consumed for Cooling & Processes (gallons/MWhr)	Assumed Capacity Factor	Annual Water Consumption for a 500 MW Plant[2]			
				Gallons per Year		Acre-Feet per Year	
				Min	Max	Min	Max
Steam-Cycle (with steam boilers)							
Natural Gas - Once-Through Cooling	10,000 - 60,000	95 - 285	40%	166 million	499 million	510	1,530
Natural Gas - Re-circulating Tower	950 - 1,460	760 - 1,170		1,332 million	2,050 million	4,090	6,290
Combined-Cycle							
Natural Gas - Re-circulating Tower	840 - 1,725	676 - 1,380[5]	40%	1,156 million	2,420 million[5]	3,500	74,005
Natural Gas - Air-Cooled	60 – 225	50 - 180		88 million	315 million	270	970
Simple-Cycle (peaking plants)							
Natural Gas with Inlet Cooling	100 – 750	80 - 600	20%	70 million	526 million	215	1,610
Renewable Technologies							
Solar Thermal							
Parabolic Trough	1,150 - 1,340	960 - 1,120	30%	1,260 million	1,470 million	3,870	4,500
Solar Tower	---	---		---	---	---	---
Sterling System	5 – 7	4 - 6		7 million	10 million	20	30
Geothermal	10 – 40	8 - 30	70%	25 million	92 million	75	282
Waste Energy – Biomass							
Steam - Re-circulating Tower	950 - 1,460	760 - 1,170	40%	1,332 million	2,050 million	4,090	6,290
Waste Energy – Landfills							
Simple-Cycle	100 - 1,040	80 - 830	40%	140 million	1,454 million	430	4,460
Reciprocating Engine	0 – 1	0 - 1		0	1.8 million	0	5

Notes:

1. Water withdrawal estimated as 20% more than the water consumed in order to account for the wastewater stream.
2. Estimated by the Energy Commission staff.
3. Water use rates do not distinguish between power plants that reuse wastewater such as from a zero liquid discharge (ZLD) systems from those that do not; ZLD can achieve approximately 15% reduction in the water consumed by a power plant.
4. Water use rates are based on data reported to the Energy Commission by power plant operators in 2005 as measured during calendar year 2003.
5. The upper limit of the range for water use of the combined cycle is higher than a steam turbine plant, both configured with re-circulating cooling towers, because the upper limit data for the combined cycle plant is attributable to a warmer desert climate requiring more water for cooling.

Sources: Hewett 2003, Department of Energy 2004, with California-specific modifications by Energy Commission Staff based on 2005 environmental survey data and Energy Commission siting cases..

Water Use for Energy Commission Jurisdictional Power Plants: 1996–2007

Since 1996, the Energy Commission has licensed, or is currently reviewing, 71 Applications for Certification (AFCs) for power plants totaling about 29,534 MW. Most of these AFCs are for new power plants, but some are for "repowers" – which means full or partial replacement of the generating units at existing sites. For the natural gas-fired power plants, nearly all of these plants use turbine-based technologies in combined-cycle or simple-cycle configurations.

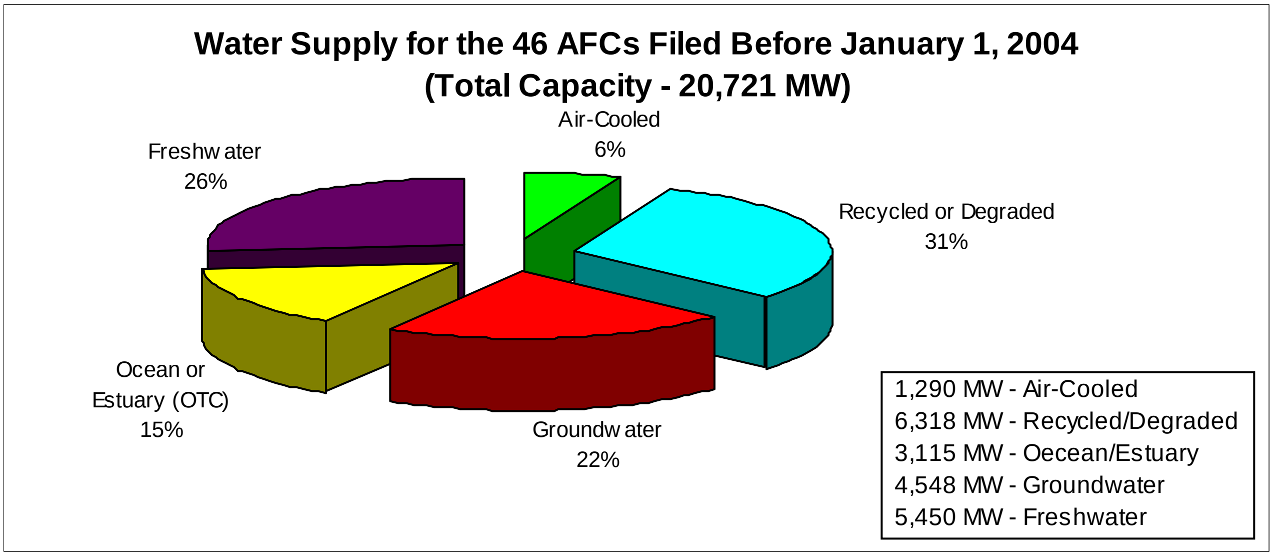
In addition to the increased thermal efficiencies and water use efficiencies inherent to turbine technologies, turbines have created the opportunity to substantially reduce the amount of freshwater and groundwater used for power plant cooling. Turbine-based power plants can use air-cooling or recycled water in closed-loop towers and can be cost-competitive with plants that use freshwater or groundwater in closed-loop towers or seawater in once-through cooling systems.

On average, combined-cycle power plants consume approximately four times more water than the same capacity simple-cycle power plant. As shown on Table 9, a 500 MW combined-cycle plant consumes on average 3,500 acre-feet of water per year, while a similarly sized simple-cycle plant consumes on average 825 acre-feet of water per year. As discussed in the previous section, water is used in simple-cycle turbines to cool the turbine's inlet air and optimize turbine performance and not for cooling waste heat.

The following discussion and figures show the trends in cooling methods and sources of water for California's power plants. Data for all 71 AFCs are divided into two categories, one before and one after adoption of the Energy Commission's 2003 Cooling Water Policy. Figure 8 shows the distribution of cooling water sources for the 46 AFCs filed between 1996 and the end of 2003, while Figure 3-3 shows distribution of cooling water sources for the AFCs filed between January 2004 and July 2007. Comparing Figures 8 and 9 illustrates the evolution in cooling technologies toward air-cooled systems and closed loop cooling towers using recycled or degraded water.

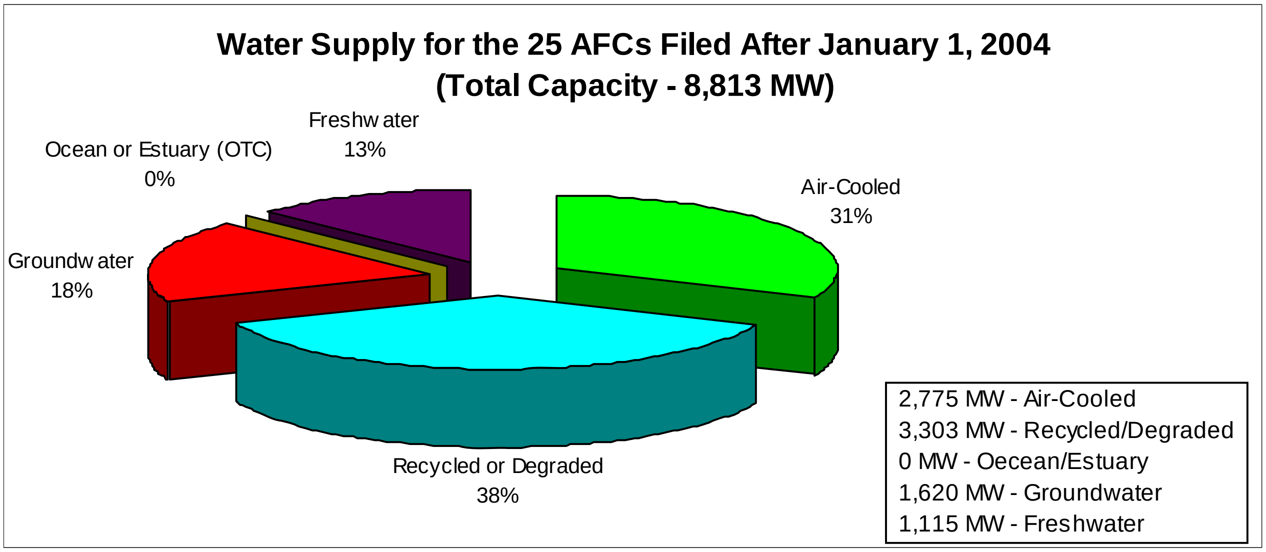
Note that the figures show water supply sources as a proportion of total capacity for each period and not as a percentage of total projects or AFCs. This dataset combines AFCs for combined-cycle and simple-cycle peaker project. Note as well that this dataset includes all AFCs filed before the Energy Commission and does not distinguish between plants actually constructed and license applications that were withdrawn or never exercised. Appendix A contains a table showing complete information for these projects.

Figure 9: Water Supply Sources on a Capacity Basis for the 46 AFCs Filed Between 1996 and 2003



Source: Energy Commission Power Plant Siting and Cooling System databases.

Figure 10: Water Supply Sources on a Capacity Basis for the 25 AFCs Filed After January 2004



Source: Energy Commission Power Plant Siting and Cooling System database.

Figure 8 shows that between 1996 and the end of 2003 when the Cooling Water Policy was adopted, 46 percent of the 20,721 MW of capacity for the 46 projects proposed to use freshwater or groundwater for cooling. Another 15 percent of the projects' capacity proposed to use sea water or estuary water in once-through cooling processes. About one-third of the applicants designed their projects to use recycled water (total of 6,318 MW).

Figure 9 shows cooling systems and source water for the 25 power plant licensing applications totaling 8,813 MW filed at the Energy Commission after January 2004 when the Cooling Water Policy came into effect. On a capacity basis through 2007, 69 percent of the power plants will use recycled water or air-cooling. This is a major increase from the 37 percent of the capacity using recycled water or air-cooling in the pre-2004 set of power plant applications. Proposed use of groundwater and fresh water dropped to 31 percent on a capacity basis, most of which have been for simple-cycle peakers, which use far less water than the combined-cycle power plants. Table 10 summarizes the cooling water use by Energy Commission jurisdictional power plants for the two periods. The number of applications for power plants with air-cooling systems began to increase markedly in 2006. The number of plants proposing to use freshwater and groundwater leveled off in 2006 and is no longer increasing. No project proposals to continue using sea water for once-through cooling were received after January 2004.

Table 10: Trends in Cooling Water Use by California Power Plants Before and After Adoption of the 2003 Cooling Water Policy (Percent of Capacity by Source Water)

Period	Total AFCs	Total MW	Source Water and Cooling Technology (percent of total capacity)				
			Surface Water	Ground-water	Sea Water	Recycled Water	Air Cooling
1996-2003	46	20,721	26	22	15	31	6
2004-2007	25	8,813	13	18	0	38	31

The trend towards increasing proposals to use recycled or degraded water and air cooling illustrated above is even more pronounced for the subset of power plant applications current in licensing review at the Energy Commission. As presented in Table 11 below, the most recent applications for certification or amendment filed with the Energy Commission since 2005 total 8,409 MW (representing 19 power plants). A total of 77 percent (6,442 MW) of the power plants on a capacity basis will use air-cooling or recycled water in closed-loop towers, including all of the large combined-cycle projects. The three projects proposing to use fresh water or groundwater are all simple-cycle peakers.

Another benefit of power plants using recycled water is that the pipeline needed to serve the power plant often extends a main line for supplying recycled water over several miles of a purveyor's service area where it does not exist already. Therefore, the recycled water supply development for serving power plants can often provide backbone infrastructure for expanding service for other uses within a region, including irrigation and industrial. As an example, the Tesla Power Plant licensed in 2004 and pending construction would develop an 11-mile recycled water pipeline originating from the City of Tracy's wastewater treatment plant that would extend recycled water service where there is none currently. The lack of infrastructure, and mechanisms to finance it, is a limiting factor throughout the state in expanding use of recycled water. Therefore, development of recycled water infrastructure to serve new power plants can contribute to broader conservation of fresh water within the region and overall in the state.

Based on water consumption, on average, air-cooled system designs use far less water (90 acre-feet per year) than water-cooled designs. The 90 acre-feet per year consumed on average in air-cooled systems is used for inlet and inter-cooling, sanitation, and other plant operations. When viewed as a function of optimizing water use, air-cooled designs out-perform water-cooled systems by at least five or more times, on average using only 0.19 acre-feet per MW.

Table 11: Water Use for Applications and Amendments Currently in Review at the Energy Commission

System Cooling Type	Capacity (MW)	Water Consumption (AFY)	Water Consumption (AFY per installed MW)
Air-Cooled Design			
1. Colusa - E&L Westcoast	660	126	0.19
2. Eastshore – Tierra Energy	116	2	0.01
3. El Segundo Repower - Dynegy/NRG	560	34	0.06
4. Humboldt Bay Repowering Project – PG&E	163	3	0.02
5. San Gabriel Generating Station – Reliant	656	220	0.34
6. South Bay Replacement Project - L.S. Power	620	129	0.21
7. Gateway (Contra Costa Unit 8) - PG&E	530	120	0.23
Total	3,305	633	
Average	472	90	0.19
Recycled or Degraded Water			
1. Sun Valley Energy Project - Edison Mission	500	851	1.7
2. Chevron Richmond Power Plant Replacement Project	60	1,486	25
3. Russell City Energy Center	600	2,490	4.2
4. Vernon Power Plant – City of Vernon	914	6,266	6.9
5. Victorville 2 Hybrid Power Project	563	3,150	5.6
6. Walnut Creek Energy Park - Edison Mission Energy	500	885	1.8
Total	3,137	15,128	
Average	523	2,521	4.8
Groundwater			
1. EIF Firebaugh Panoche - Energy Investors Fund	400	805	2
2. Highgrove – AES	300	366	1.2
3. Sentinal - CPV Sentinel	800	550	0.69
4. Starwood Firebaugh Panoche – Starwood Power-Midwa	120	14	0.11
Total	1,620	1,735	
Average	405	434	1.1
Ocean or Estuary Water for Once-Through Cooling	**0**	**0**	**0**
Freshwater (purveyor supplied)			
1. EIF Fresno/Bullard - Energy Investors Fund	200	671	3.4
2. Larkspur Energy Facility - Larkspur 3	47	---	---
3. Orange Grove Energy	100	117	1.2
Total	347	788	
Average	116	394	3.4

Note: Total water consumed includes water used for inlet cooling, steam-cycle cooling, process make-up water, sanitation, and other plant operations.

Source: California Energy Commission

Proposals to Use Air Cooling Increased Significantly in 2006 and 2007

California currently has two operational power plants that use air cooling, and a third is under construction. The number of proposals to use air cooling increased significantly in 2006 and 2007, as shown on Table 12. Seven power plant proposals to use air cooling totaling 3,305 MW were filed in 2006 and 2007. Four of these proposals are to repower coastal plants and switch from once-through cooling to air cooling; two of these projects – PG&E's Gateway Project and NRG's El Segundo Project – are amendments to recent Energy Commission licenses authorizing the continued use of once-through cooling. Two more combined cycle power plants that would use air cooling, totaling 1,150 MW, have been proposed.

In addition to the gas-fired combined cycle power plants, four large solar thermal projects have been announced that also would not require cooling water. These four projects are the initial announcements for what is expected to be a large number of applications for solar thermal power plants.

California's first two large, modern power plants using air-cooling are noteworthy. In 1996, the 240 MW combined-cycle Crocket Cogeneration plant at the C&H sugar refinery became operational. The use of air-cooling at this site is remarkable because the refinery is directly next to the Carquinez Straits in the San Francisco Bay-Delta where several other power plants use once-through cooling systems, and because the cogeneration plant was built on top of the sugar refinery. The 540 MW Sutter Power Project in Sutter County that came on-line in 2001 was the first large combined cycle combustion turbine plant to be built in California using air-cooling. This project is notable because Sutter County is in the Sacramento Valley with its large volumes of river and project water that is used for rice and other water-intensive crops.

Table 12: Air-Cooled Power Plants in California (Energy Commission Jurisdiction)

Air-Cooled Power Plants 1997 – 2003				
Power Plant Name and Owner	**Generator Type**	**System Cooling**	**Installed Capacity (MW)**	**Status**
Crockett Cogeneration - Delta Power[1]	Combined- Cycle	Air-Cooled Condenser	240	Operational
Otay Mesa – Calpine	Combined- Cycle	Air-Cooled Condenser	510	Under Construction
Sutter Power Project – Calpine	Combined- Cycle	Air-Cooled Condenser	540	Operational
Total Number of Plants: 3		Total Capacity: 1,290 MW		
Air-Cooled Power Plants 2004 – 2007				
Power Plant Name – Owner	**Generator Type**	**System Cooling**	**Installed Capacity (MW)**	**Status**
Eastshore Energy Center - Tierra Energy	Gas-Fired Reciprocating Engine	Air-Cooled Radiator	116	Review
Humboldt Bay Repowering Project - PG&E*	Dual-Fuel Reciprocating Engine	Air-Cooled Radiator	163	Review
Colusa Generating Station - E&L Westcoast	Combined-Cycle	Air-Cooled Condenser	660	Review
El Segundo Repower - Dynegy/NRG[2*]	Combined- Cycle	Air-Cooled Condenser	560	Review
Gateway (Contra Costa Unit #8) - PG&E[3*]	Combined- Cycle	Air-Cooled Condenser	530	Under Construction
San Gabriel Generating Station – Reliant	Combined- Cycle	Air-Cooled Condenser	656	Review
South Bay Replacement Combined Cycle - L.S. Power*	Combined- Cycle	Air-Cooled Condenser	620	Review
Total Number of Plants: 7		Total Capacity: 3,305 MW		
Air-Cooled Power Plants Announced But Not Yet Filed before the Energy Commission				
Power Plant Name – Owner	**Generator Type**	**System Cooling**	**Capacity (MW)**	**Status**
Avenal 2 - Federal Power	Combined-Cycle	Air-Cooled Condenser	600	Planning
Carlsbad – NRG	Combined-Cycle	Air-Cooled Condenser	550	Planned
Total Number of Plants: 2		Total Capacity: 1,150 MW		
Solar Air-Cooled Power Plants Announced But Not Yet Filed before the Energy Commission				
Power Plant Name – Owner	**Generator Type**	**System Cooling**	**Capacity (MW)**	**Status**
Stirling Solar Thermal One – Stirling Energy Systems	Stirling Engine	Air-Cooled Radiator	850	Planning
Stirling Solar Thermal Two – Stirling Energy Systems	Stirling Engine	Air-Cooled Condenser	900	Planned
Ivanpah Solar Power Plant - Bright Source Energy	Solar Thermal Tower	Air-Cooled Condenser	300	Planned
Aursa-Carrizo – Ausra	Solar Thermal Trough	Air-Cooled Condenser	180	Planned
Total Number of Plants: 4		Total Capacity: 2,230 MW		

Source: Energy Commission Siting Database

1. The first air-cooled power plant, located on the Carquinez Strait, became operational in 1996.
2. Project originally approved with an ocean intake and once through cooling.
3. Project originally approved to use river water for cooling; it is now under review to use air-cooling.

Wastewater Discharge Trends

Historically, power plants have had residual water (wastewater) that was not reusable in the plant operations. This wastewater was either discharged to surface waters, deeply injected into the ground, sent to a sanitary sewer for processing, discharged to an evaporation pond for evaporation and groundwater recharge, or trucked offsite for disposal at a landfill or treatment facility. Each of these disposal methods involves varying degrees of risk of potential impact to the environment and vary in efficient use of natural resources.

Since the beginning of 2004, the trend in wastewater discharge is towards the use of zero liquid discharge (ZLD) systems and sanitary sewers.

Table 13: Summary of Wastewater Discharge for Jurisdictional Power Plants in California

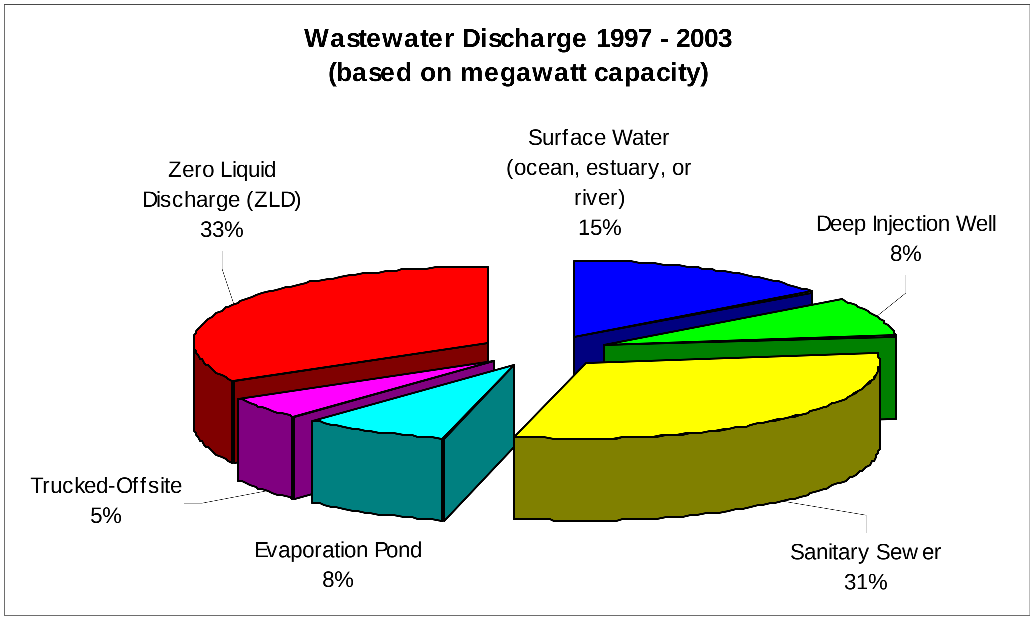
	Number of Power Plants				Capacity (MW)			
Wastewater Discharge Destination	1997 - 2003		2004 - 2007		1997 - 2003		2004 - 2007	
Surface Water	6	12%	1	4%	3,021	15%	43	0.70%
Deep Injection Well	3	6%	2	8%	1,659	8%	485	5%
Sanitary Sewer	20	39%	12	46%	6,246	31%	4,681	52%
Evaporation Pond	3	6%	2	8%	1,670	8%	120	1%
Trucked-Offsite	7	14%	1	4%	947	5%	100	1%
Zero Liquid Discharge (ZLD)	12	24%	8	31%	6,782	33%	3,484	39%
Totals	**51**		**26**		**20,325**		**8,930**	

Source: Energy Commission Siting Database

The data in Table 13 and Figures 10 and 11 illustrate this trend. Before 2004, on a per megawatt basis, the two most common wastewater disposal methods were zero liquid discharge (33 percent) and sanitary sewer (31 percent). Since 2004, there has been an increase in ZLD plant designs from 33 to 39 percent. All discharge categories are down or declining except discharge to sanitary sewer systems, which increased 23 percent from pre-2004 to post 2004, totaling 52 percent of the capacity licensed between 2004 and 2007. Since the beginning of 2004, it has been the policy of the Commission to promote the use of zero liquid discharge for recycling power plant wastewater.

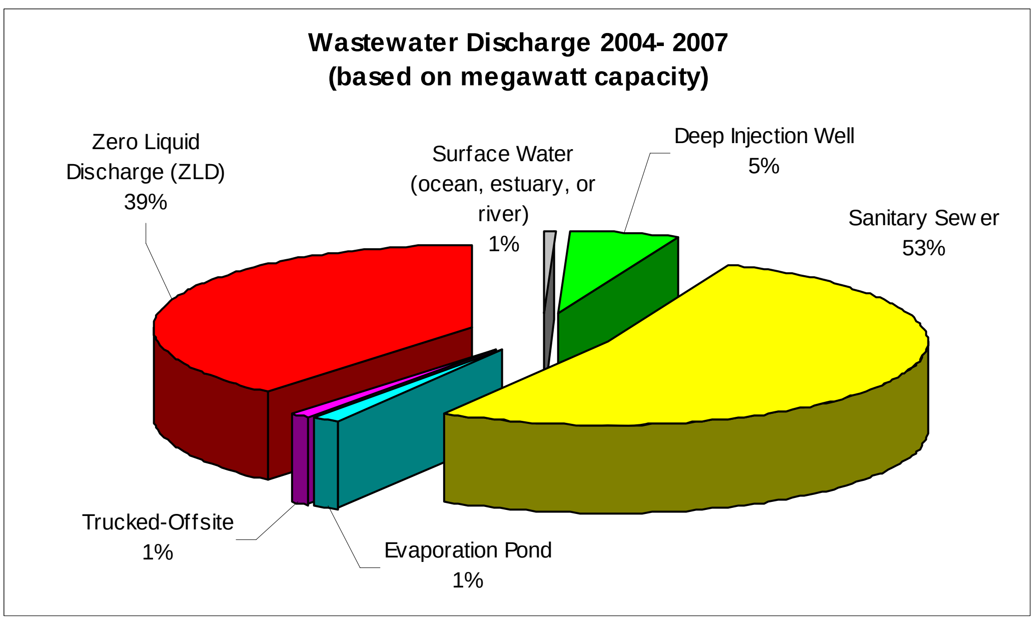
Focusing on applications for certification and amendments currently in review at the Energy Commission, Table 14 presents a summary of the proposed wastewater disposal methods. Based on this data, the trend continues with the use of sanitary sewers as the most commonly used wastewater disposal method. Over half, 10 of the 19 applications and amendments, propose the use of sanitary sewers, with only about a third proposing the use of a ZLD system. In the coming years, the trend in the use of ZLD designs is expected to conform with the water policy.

Figure 11: Wastewater Discharge Methods for 51 Power Plants Totaling 20,325 MW Reviewed Between 1997 and 2003



Source: Energy Commission Siting Database

Figure 12: Wastewater Discharge Methods for 26 Power Plants Totaling 8,930 MW Reviewed Between 2004 and 2007



Source: Energy Commission Siting Database

Table 14: Wastewater Disposal Methods for Current Applications and Amendments in Review at the Energy Commission

Wastewater Disposal Method	Capacity (megawatts)
Surface Water (ocean, estuary, or river water)	
1. Chevron Richmond Power Plant Replacement Project	60
Deep Injection Well	
1. EIF Firebaugh Panoche - Energy Investors Fund	400
Sanitary Sewer	
1. Eastshore - Tierra Energy	116
2. EIF Fresno/Bullard - Energy Investors Fund	200
3. Highgrove - AES	300
4. Humboldt Bay Repowering Project - PG&E	163
5. Larkspur Energy Facility - Larkspur 3	47
6. San Gabriel Generating Station - Reliant	656
7. South Bay Replacement Projects - L.S. Power	620
8. Sun Valley Energy Project - Edison Mission	500
9. Vernon Power Plant - City of Vernon	914
10. Walnut Creek Energy Park - Edison Mission Energy	500
Total	**4,016**
Average	402
Evaporation Pond	
1. Starwood Firebaugh Panoche - Starwood Power-Midway	120
Trucked-Offsite	
1. Orange Grove - Orange Grove Energy	100
Zero Liquid Discharge (ZLD)	
1. Colusa - E&L Westcoast	660
2. El Segundo Repower - Dynegy/NRG	560
3. Russell City Energy Center - Russell City Energy Company	600
4. Sentinal - CPV Sentinel	800
5. Victorville 2 Hybrid Power Project	563
Total	**3,183**
Average	637

Source: Energy Commission Siting Database

CHAPTER 4: Once-Through Cooling Issues Update

Introduction

This chapter provides a broad overview of the legal, regulatory, policy, and market events that have occurred since the *2005 Integrated Energy Policy Report* and *Environmental Performance Report*. It includes updates on environmental impacts, legal and regulatory developments, trends in coastal plant operations and development, and nuclear power plant issues.

This chapter is also intended to serve as the basis for a status report to the California Legislature, as required by AB 1576 (Nunez, Stats. 2005, Ch. 374 § 3), on the progress being made to implement the once-through cooling performance standards as established by the U.S. Environmental Protection Agency under Section 316(b) of the Clean Water Act.

The once-through cooling (OTC) systems used by 19 California power plants along the coast are now understood by scientists and regulators to be major contributors to the degradation of marine and estuarine ecosystems.[13] As stated in the Energy Commission's 2005 staff report on once-through cooling, "California marine and estuarine environments are in decline and the once-through cooling systems of coastal power plants are contributing to the degradation of our coastal waters."[14] Since the *2005 Integrated Energy Policy Report*, significant regulatory and legal actions have occurred that will likely lead to an eventual phase out of this cooling technology at most, if not all, of the 17 fossil-fueled coastal power plants in California. It is unclear how the state's two nuclear power plants will be affected.

Overview of Once-Through Cooling Impacts

Sea water provides an abundant source of cooling water that is highly effective at cooling gas-fired and nuclear power plants. The 19 power plants in California that use this cooling technology are allowed to cycle from about 100 million gallons per day (MGD) for the smaller plants to 2.5 billion gallons per day (BGD) for the two large nuclear plants. Cumulatively, the California fleet is permitted to cycle up to 16.3 billion gallons per day, or about 50,000 acre-feet of sea water each day. However, with the exception of the two nuclear facilities, most of the California coastal fleet operates well below their design capacity and permitted levels. Not-yet-published data from the

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[13] Impacts due to entrainment and impingement as cooling water is withdrawn and cycled through a power plant's cooling system are the focus of current scientific inquiries and legal and regulatory actions. The impacts from thermal discharges occurring after the heated water is pumped back to the source waters are generally well understood and regulated.

[14] *Issues and Environmental Impacts Associated with Once-Through Cooling at California's Coastal Power Plants*, California Energy Commission Staff Report Prepared in Support of the *2005 Integrated Energy Policy Report*, June 2005, CEC Report No. 700-2005-013.

State Water Resources Control Board indicates that actual water flows through the once-through cooling systems declined from 13.5 BGD in 2001 to 9.4 BGD in 2005.[15]

Impacts are classified as “entrainment,” where microscopic level organisms are drawn through cooling water intakes and killed as they are cycled through the plant, “impingement,” where larger organisms such as fish and marine mammals are pinned against the intake screens and killed, and “thermal impacts,” which describes impacts to ecosystems when the warmed water is discharged back to the cooler source water.

Near-shore marine and estuarine waters are nutrient rich, highly productive ecosystems. These waters provide habitat for innumerable phytoplankton, zooplankton, and invertebrates, as well as the eggs and larval stages for near-shore and off-shore fish, shellfish, crabs and lobsters, and the spores for critical marine plant species like kelp. These ecosystems form a critical part of the marine food web for the larger fish and marine mammal species. When near-shore waters are cycled through power plants for cooling, essentially all of the marine organisms are killed. This high mortality impact to the base of the food web is now understood to contribute to the significant declines in near-shore and open ocean fish stocks.

Two influential reports on the state of the oceans produced by the Pew Commission on Oceans[16] in 2003 and the U.S. Commission on Ocean Policy[17] in 2004 documented that the other contributing factors to the alarming declines in ocean ecosystem health included over-fishing, non-point source pollution from urban and agricultural areas, sewage contamination, and exotic species infestations of localized ecosystems.

Three primary types of near-shore and estuarine habitats are affected by once-through cooling systems: bays and estuaries, open coast sand and rock, and open coast sand and harbor. In bays such as Santa Monica, Monterey, and San Diego and estuaries like the San Francisco Bay-Delta and Elkhorn Slough, the impacts from entrainment and impingement can be even more pronounced due to the high biological productivity of these ecosystems and the concentration of multiple power plants using once-through cooling. In Santa Monica Bay for example, the three large power plants using once-through cooling – Scattergood, El Segundo, and Redondo – cycle 13 percent of the bay’s near-shore waters every six weeks.[18] Eleven of the 19 coastal power plants using once-through cooling are located on the shores of bays or estuaries.

The San Francisco Bay-Delta estuary is the largest estuary on the West Coast of the Americas. Two old power plants on the shore of this estuary that continue to use once-through cooling – Pittsburg and Contra Costa – entrain and impinge endangered species such as the Delta smelt and Chinook

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[15] Adam Laputz, Water Quality Engineer, State Water Resources Control Board, Personal Communication, July 16, 2007. The actual correlations between power production and once-through cooling throughput levels are not well understood because the water use rate (gallons per MWh of production) varies widely within the coastal fleet and because many power plants operate their pumps during periods on non-power production. The forthcoming study by the State Water Board’s Ocean Unit should help provide additional data and insight into these correlations.

[16] *America’s Living Oceans: Charting a Course for Sea Change, A Report to the Nation*, Pew Oceans Commission, Leon Panetta, Chair, May 2003.

[17] *Preliminary Report of the U.S. Commission on Ocean Policy*, A Report to Congress, April 2004.

[18] *Issues and Environmental Impacts Associated with Once-Through Cooling at California’s Coastal Power Plants*

salmon.[19] All of the federally listed, imperiled salmon species migrating in and out of the Sacramento and San Joaquin River watersheds – Chinook salmon, coho salmon and steelhead trout – must also pass the intakes for these plants.

Cooling water intakes for the larger power plants can also impinge large volumes of adult fish, as well as occasional marine mammals such as sea otters and seals, and sea turtles. Part of the Energy Commission-required studies to assess impacts from the Huntington Beach Power Plant's once-through cooling system found that annual cumulative impingement for the 11 coastal plants in Southern California total 3.6 million fish weighing about 58,000 pounds. This represents from 8 to 30 percent of the total catch from recreational fishing for the 11-plant study area.

Overview of Key Regulatory Actions and Legal Events Related to Once-Through Cooling

The two major science and policy reports on the degraded state of the nation's oceans issued in 2003 and 2004 – U.S. Commission on Ocean Policy and the Pew Commission on Oceans – sparked public concern about continuing impacts to the Pacific and Atlantic Oceans. This public concern coincided with the increased scientific understanding of the environmental impacts of once-through cooling systems and created an array of regulatory actions from state and federal agencies to reduce once-through cooling impacts. Concurrently, the Second Circuit Court of Appeals in New York issued two major decisions that may lead to an eventual phase out of most once-through cooling systems.

This section summarizes these key regulatory, legislative, and legal actions:

2004

- The **Riverkeeper** environmental group challenges the U.S. Environmental Protection Agency's interpretation of the Clean Water Act in the new 316(b) regulations for once-through cooling in new power plants (known as the Phase I Rule). While the **Second Circuit Court of Appeals** upheld US EPA's new environmental performance standards in ***Riverkeeper v US EPA (Riverkeeper I)*****,** the Court also ruled that the use of off-site restoration as a mitigation measure for once-through cooling impacts did not conform to the Clean Water Act, effectively precluding the use of once-through cooling at new, large power plants.
- The **U.S. Environmental Protection Agency** issues its final rule for regulation of once-through cooling systems for existing large power plants (known as the 316(b) Phase II Rule). Although EPA found that "there are multiple types of undesirable and unacceptable environmental

[19] "Impingement at power plants has the potential to directly cause mortality or takes of endangered fish species. As an example, the Contra Costa Power Plant has been known to entrain Chinook salmon and Delta smelt (316b PIC for Mirant Contra Costa Power Plant, Tenera Environmental, April 2006). Site-specific impacts such as these must be minimized and ultimately mitigated for…," State Water Resources Control Board Proposed Statewide Policy on Clean Water Act Section 316(b) Regulations, June 13, 2006.

impacts associated with once-through cooling technology," the regulations establish a series of "best technology available" (BTA) compliance options that create wide latitude for power plant owners to comply with the new regulations without reducing physical impacts.

- The **California Legislature** enacts the **Ocean Protection Act** in response to public concerns about ocean health highlighted in the two national reports. The Act creates the Ocean Protection Council, which is a cabinet-level policy council charged with coordinating actions of state environmental regulatory agencies to improve the state of ocean ecosystems.

2005

- The **State Water Resources Control Board**, which has been delegated federal Clean Water Act authority to regulate once-through cooling in California, initiates a public proceeding to determine if a new rule is needed to interpret US EPA's 316(b) regulations to meet state of California environmental policy objectives.
- **Energy Commission staff** prepares a major report - *Issues and Environmental Impacts Associated with Once-Through Cooling at California's Coastal Power Plants* - summarizing impacts and the state of the science on once-through cooling based on experience with six coastal siting cases.
- Drawing from the staff report, the **California Energy Commission** finds in the ***2005 Integrated Energy Policy Report*** that once-through cooling "can contribute to the decline of fisheries and the degradation of estuaries and bay and coastal waters." The Commission directs staff to work cooperatively with other state agencies to address once-through cooling issues in the broader context of protecting the state's fragile coastal marine ecosystem. The Commission directs Public Interest Energy Research (PIER) funding to be used to further refine scientific methods on impact assessment.
- The **California Legislature passes AB 1576** (Nunez, Statutes of 2005), which 1) directs the **California Public Utilities Commission** to create a process that allows coastal merchant generators to receive cost-of-service rates for costs expended to modernize coastal power plants and increase their environmental performance, and 2) directs the Energy Commission to prepare a status report in the *2007 Integrated Energy Policy Report* on progress made to implement the U.S. Environmental Protection Agency's 316(b) performance standards for once-through cooling intakes.

2006

- The **California State Lands Commission** issues a "**draft resolution"** expressing concern about once-through cooling impacts. The resolution proposed to deny power plant owners the renewals of leases to use state lands after 2020 if infrastructure related to once-through cooling was located on the subject state lands. The Council on Economic and Environmental Balance (CEEB) filed a request for a regulatory determination from the Office of Administrative Law, which found that the resolution constituted an "underground regulation."

- The **Ocean Protection Council** issues a **Resolution** concurring with the US EPA findings that "once-through cooling impacts can be significant." The Council encourages the State Water Resources Control Board to enact more stringent requirements for state regulation of once-through cooling and form an interagency committee of environmental and energy agencies to work to resolve the once-through cooling issues. The Council also provided funding for a set of studies on coastal power retrofit issues and electric system reliability issues.

- **State Water Resources Control Board staff** issues a "**proposed policy"**[20] that would significantly strengthen regulation of cooling water intake structures under State interpretation of 316(b) of the Clean Water Act.

  - The Coastal Commission, Department of Fish and Game, State Lands Commission, and the National Marine Fisheries Service express general support for the goals and approach of the regulations, although many agencies had concerns about specific parts of the proposed regulations.

  - The Energy Commission comments that while it recognizes the need to reduce once-through cooling impacts, it is critical that implementation of the proposed 316(b) rule not undermine the reliability of California's electricity system. The Energy Commission suggests that repowering the existing steam plants on the coast to more efficient combustion turbine technologies would also create the opportunity for owners to switch to dry cooling or closed-loop towers using recycled water.

- The **California Energy Commission** finalizes the CEQA Review and mitigation requirements for the 2001 license that allowed the **Huntington Beach** power plant to continue using once-through cooling. The Energy Commission's 2007 decision requires mitigation of $5.5 million for the purchase and restoration of 66.8 acres of tidal wetlands, based on staff's methodology for impact assessment and mitigation.

- The **California Public Utilities Commission** begins a process within the Long-Term Procurement Proceeding (R-06-02-013) to create standards and procedures **to enact the cost-recovery provisions of AB 1576.** Mirant, NRG and LS Power, all of which own coastal power plants using once-through cooling, actively participate in efforts to create a cost-recovery process in accordance with AB 1576.

2007

- The **Second Circuit Court of Appeals rules in Riverkeeper v US Environmental Protection Agency (Riverkeeper II)** that the recent 316(b) Phase II regulations for existing large power plants do not conform to major tenets of the Clean Water Act. The Court affirms that the CWA requires the use of "best technology available" (BTA) to reduce physical impacts to aquatic ecosystems, and that the use of restoration, cost-benefit tests, ranges of flow-reduction targets and other schemes US EPA classified as BTA did not conform to the Act. The Court upheld US

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[20] *Scoping Document and Proposed Statewide Policy on Clean Water Act 316(b) Regulations*, California State Water Resources Control Board, June 13, 2006. http://www.waterboards.ca.gov/npdes/docs/cwa316b/316b_scoping.pdf

EPA's interpretation of "adverse environmental impact[s]" from once-through cooling and affirmed that the CWA requires that such impacts be minimized.

- In response to the Second Circuit decision, the **U.S. Environmental Protection Agency** formally suspends its 316(b) Phase II regulations for existing, large power plants on July 9. According to Mary Smith of the Office of Water, US EPA plans to begin a new rulemaking in October 2007.[21]

- The **U.S. Nuclear Regulatory Commission** (NRC) ruled on April 11, 2007 that the decision on whether to allow the Vermont Yankee nuclear facility to discharge warmer water into the Connecticut River is a state issue, not a federal issue. NRC ruled that the Clean Water Act "precludes [the NRC] from either second guessing the conclusions in NPDES permits or imposing [its] own effluent limitation – thermal or otherwise." [22]

- **Surfrider Foundation** files a legal challenge in July against the San Diego Regional Water Quality Control and State Water Resources Control Board for their 2006 renewal of the National Pollution Discharge Elimination System (NPDES) permit for NRG's Encina Power Plant in San Diego. The Petition for Writ of Mandate asserts that the permit does not conform to the recent Second Circuit Decision. This is the first legal challenge to a plant-specific NPDES 316(b) permit in California based on the Second Circuit Decision.

- The **Coalition for a Sustainable Delta**, representing local water districts and irrigators, announce plans in September to sue Mirant Delta LLC and the U.S. Army Corps of Engineers over alleged violations of the Endangered Species Act in the San Francisco Bay-Delta. The group asserts that Mirant's two power plants in the Delta (Pittsburg and Contra Costa) illegally kill Delta smelt and other endangered fish species through use of their once-through cooling systems.[23]

- **Owners of five coastal power plants** in California announce plans to switch to dry cooling as part of their plans to modernize and repower their existing facilities. Two of those companies, which hold recent licenses from the Energy Commission that would have allowed the continued use of once-through cooling, voluntarily file amendments to change to air cooling.

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[21] "Discharge Permits: EPA Suspends Cooling Water Rule In Response to Second Circuit Decision," vol. 38, Env't Rep. (BNA), No. 27, at 1481 (July 6, 2007).

[22] NRC Order, Docket No. 50-271-LR, Memorandum and Order, April 11, 2007, in the matter of Entergy Nuclear Vermont Yankee, LLC, & Entergy Nuclear Operations, Inc, pp. 4-5.)

[23] "Coalition Plans to Sue Government, Power Firm to Save Delta Smelt," San Francisco Chronicle, September 28, 2007

Energy Commission Staff Contributions to Interagency Efforts to Reduce Once-Through Cooling Impacts

Energy Commission staff has worked actively to provide information to the Ocean Protection Council, State Water Board, State Lands Commission, and other agencies involved with once-through cooling issues. In particular, Energy Commission staff has provided substantial amounts of technical information on coastal power plant operations, resource adequacy and local reliability issues to the State Water Resources Control Board staff and to the contractors working on the cooling tower retrofit feasibility study and grid reliability study funded by the Ocean Protection Council. Energy Commission staff contributions to interagency efforts include:

- Assessment of impacts to marine and estuarine environments from once-through cooling based on staff analysis of six coastal power plant licensing applications;
- Scientific support from the PIER Program on fundamental scientific questions about ecosystems functions, species diversity, and appropriately and consistently measuring impacts from once-through cooling in different types of ecosystems;
- Information on alternative cooling systems from the PIER Program and facility siting experience with inland and coastal plants seeking to use air cooling;
- Information on coastal plant operations, resource adequacy, and other energy issues associated with potential impacts to grid reliability from proposed regulatory changes on once-through cooling;
- Consultation with the California Independent System Operator and CPUC on the intersection of environmental regulation with power production and transmission;

Recent PIER Work on Once-Through Cooling and Alternative Cooling

The *2005 Integrated Energy Policy Report* directed PIER to work with other agencies and use its research funding and capacity to "develop sampling and other analytical protocols and guidelines that will provide clear, consistent approaches for assessing the ecological effects of once-through cooling."

Table 15: PIER-Sponsored Research On Once-Through Cooling

Principal Investigator	Affiliation	Title
Pondella, Daniel	Occidental College	The Ichthyoplankton of King Harbor, Redondo Beach, CA 1974-2006
Largier, John	UCD Bodega	Improving Assessment of Entrainment Impacts Through Models of Coastal and Estuarine Withdrawal Zones
Cech, Joseph	UCD	Bright Vibrating Screens: Increasing the Detectability of Fish Screens
Geller, Jonathan	MLML	Molecular Identification and Enumeration of Invertebrate Larvae Potentially Entrained by OTC in Morro Bay and Elkhorn Slough, CA
Strange, Liz	Stratus Consulting	Improve impact assessment and mitigation
Raimondi, Pete	UCSC	The Efficacy of Target Species in ETM Calculations
Mitchell, Charles	MBC Applied Env Sci	Life History Parameters of Common Nearshore Marine Fishes

Source: Energy Commission PIER Program Environmental Area

PIER is also sponsoring research on the use of salt water in closed loop cooling towers. A major report on this topic is scheduled for release in late 2007.

Trends in Coastal Plant Operations

The operation of individual coastal power plants depends on their technology type, geographic location, duty cycle, and relative contribution to local reliability or general resource adequacy. Table 16 shows power plant-level operational data for the coastal fleet for 2006-2007. Unit-level operational data is provided in Appendix B. The 19 operational power plants on the coast total 21,250 MW, which represents about one third of total in-state generating capacity. ***All of the available capacity from the coastal fleet is critical to meeting summer peak power demands.*** In 2007, four of the power plants had "reliability-must-run" (RMR) contracts totaling 2,103 MW with the California Independent System Operator (California ISO), which means that their capacity is critical to meeting local reliability requirements.

Moreover, the California ISO has identified the need for additional capacity in 2007 and 2008 in specific geographic zones in order to meet "local capacity requirements" (LCR) in resource-constrained areas. For 2007, the existing capacity needed to meet LCR is 22,113 MW across 10 zones, many of which are coastal urban areas containing older steam boiler facilities.[24] In other words, the existing coastal fleet contributes important capacity reserves to help meet the LCR goals. For 2008, the existing capacity needed to meet LCR will increase to 26,899 MW.

It is important to distinguish between capacity reserves and operational levels when considering once-through cooling impacts from coastal power plants. While it is critical that the existing capacity from the coastal fleet be available to meet summer peak demands, it is also important to understand that these peak demand periods may be of relatively short duration. Some facilities may operate at full capacity for just a few hundred hours per year. Impacts from once-through cooling occur primarily while the plant is operating, and to a lesser amount while the plant is in stand-by mode, but the once-through cooling pumps continue to circulate water through the cooling systems. The following section on operations and capacity factors examines this issue in more detail.

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[24] *2008 Local Capacity Technical Analysis: Report and Study Results*, Table at page 4, California Independent System Operator, April 3, 2007. Unlike the RMR program, specific plants identified to meet LCR are not named due to proprietary concerns.

Table 16: 2006-2007 Operations Data for the Coastal Power Plant Fleet

Power Plants	2006 Capacity[1] (MW)	2006 Generation (GWh)	2006 Capacity Factor[2] %	2001 Capacity Factor %	2007 RMR Contract[3] (MW)
Alamitos	1,970	1,677	9.7	47	
Contra Costa	680	139	2.3	55.8	
Diablo Canyon (Nuclear)	2,202	18,465	95.7	94.1	
El Segundo	670	617	10.5	32.7	
Encina	965	1,255	14.8	46.5	946
Harbor	462	210	5.2	25.5	
Haynes[4]	1,606	3,482	24.7	24.1	
Humboldt Bay	137	441	36.8	56.1	106
Huntington Beach	1,013	1,141	12.9	14.9	
Mandalay	573	315	6.3	42.2	
Morro Bay	912	324	4.1	51.7	
Moss Landing[4]	2,484	6,405	29.4	68.5	
Ormond Beach	1,613	473	3.3	45.7	
Pittsburg	1,370	447	3.7	57.9	
Potrero	363	555	17.4	36.3	362
Redondo Beach	1,343	583	5	53.7	
San Onofre (Nuclear)	2,254	13,570	68.7	76.7	
Scattergood	803	1,498	21.3	24.8	
South Bay	709	959	15.5	31.8	689
Totals	**21,250**	**52,557**			**2,103**

Sources: Generation and Capacity, Energy Commission Quarterly Fuels Energy Report Database
RMR Contract Status, California ISO 2007 Local Area Reliability / RMR Contract Status Report

Notes: [1] These capacity figures are only for the steam boiler, combined cycle and nuclear units that use once-through cooling. Many of the coastal power plant sites also have combustion turbine peakers, which do not require cooling water.

[2] Capacity factors indicate annual generation as a proportion of total possible annual generation if the plant were to operate at full capacity for all 8,760 hours in a year. “Capacity factor” should not be confused with the capacity provided by coastal power plants during periods of peak demand, when all available capacity is needed to ensure resource adequacy and grid reliability.

[3] This column shows only the California ISO RMR contracts needed for local reliability. It does not include the new “local capacity requirements” because those designations are deemed proprietary. It is assumed that several more coastal power plants are included in the local capacity requirements.

[4] Haynes and Moss Landing both have partially repowered to combined cycle units, while retaining some of the older steam boiler capacity. Moss Landing’s 1,060 MW combined cycle units ran at a 56 percent capacity factor in 2006.

On an energy production basis, the coastal fleet produced 52,557 GWh in 2006, or 22 percent of total in-state electricity sales. The two large nuclear power plants, which run in a baseload duty cycle, accounted for 60 percent of the coastal fleet's electricity production in 2006. Total energy production from the coastal fleet has decreased by nearly half since 2001, when 99,832 GWh was produced. While total energy production from the coastal fleet decreased by 43 percent between 2001 and 2005,[25] not-yet-published data from the State Water Resources Control Board indicate that cooling water throughput flows decreased by 30 percent during the same period – from 13.5 billion gallons per day in 2001 to 9.4 billion gallons per day in 2005. This non-linear correlation is likely due to the fact that coastal power plant operators continue to operate once-through cooling pumps during periods of non-power generation. Therefore, caution should be used when correlating decreases in electricity generation with presumed decreases in environmental impact.

The capacity factor of a power plant denotes how much power it produces in a year relative to its potential production if it were to run at full capacity for all 8,760 hours in a year. In 2006, 11 of the 17 gas-fired power plants ran at or below a 15 percent capacity factor, which reflects that most of the older steam boiler units were used for load following and peaking, rather than for the baseload generation for which they were designed. Only the Huntington Beach Power Plant ran below a 15 percent capacity factor in 2001. Four large plants that ran above 50 percent capacity factors in 2001 – Contra Costa, Pittsburg, Morro Bay, and Redondo Beach – all ran below 5 percent capacity factors in 2006.

The Humboldt Bay Power Plant ran at about a 37 percent capacity factor in 2006, which reflects its role as the only large central station power plant in a geographically isolated part of California. The nuclear power plants ran at far higher capacity factors due to their baseload duty cycles.

Moss Landing Power Plant's production for 2006 illustrates the difference in operations for power plants that have repowered to combined-cycle technology. On a plant-level basis, Moss Landing's four units ran at a 29.4 percent capacity factor. On a unit-level basis though, the new combined-cycle units ran at a 56 percent capacity factor, which is a baseload duty cycle, and which is comparable to other new combined-cycle power plant capacity factors. The two old steam boiler units ran at 6 percent and 10 percent capacity factors.

The Los Angeles Department of Water and Power also partially repowered several units at the Haynes Power Plant to combined cycle technology while retaining the once-through cooling system. Several steam boiler units remain operational. Haynes also has relatively high generation levels at the new combined cycle units that are masked by the low capacity factors at the steam boiler units.

It is important to evaluate the unit-level capacity factors as well as the power plant-level capacity factors to fully understand how all the units within the coastal fleet are operating. This is especially true if capacity factor levels may be used in a regulatory proposal, as the State Water Board did with its 15 percent capacity factor exemption threshold in its 2006 proposed policy.

[25] Based on data provided in Appendix B for plant-level capacity factors.

Trends and Issues with Coastal Power Plant Development

The development and operation of California's coastal power plant fleet has gone through dramatic changes since 2005. Of the original 21 operational plants in 2005, two have shut down or stopped using their once-through cooling systems, and four have announced plans to repower and switch to air cooling. Owners of a proposed new large unit licensed to use once-through cooling have also announced plans to switch to air cooling. It is further anticipated that the Potrero power plant in San Francisco will be retired when the San Francisco Reliability Project is completed.

25 Percent of the Coastal Plants Switch to Dry Cooling

Table 17 shows the current status of the coastal plants. The five coastal power plants that have filed applications or license amendments with the Energy Commission to change from once-through cooling to air cooling are highlighted on the table.

On a plant-level basis, 25 percent of the coastal fleet will change from once-through cooling to air cooling. If only the 17 operational fossil-fired power plants are considered, the five plants switching to air cooling comprise nearly one-third of the fossil-fired fleet. On a capacity basis, these five projects total 2,343 MW of modern, efficient generation.

The five plants proposing to switch from once-through cooling are described further:

- **El Segundo** – NRG was granted a license in 2005 to repower this old 670 MW steam boiler to a 630 MW combined cycle power plant that would continue to use its once-through cooling system. In April 2007, three months after the 2nd Circuit decision, NRG began discussions with the Energy Commission to amend its license and switch to dry cooling. NRG creatively sought out the new Siemens turbines that can use much smaller air cooling systems than normal, allowing dry cooling to be used on the small site. NRG filed a formal license amendment application in July 2007 to switch to dry cooling.
- **Encina** – NRG filed an Application for Certification on September 14, 2007 to repower Units 1, 2, and 3 of this large 929 MW steam boiler facility in San Diego. The new Carlsbad Energy Center will use combined cycle technology totaling 558 MW. NRG plans to use the new Siemens turbines at this facility as well. The remaining Units 4 and 5 (total of 608 MW) and their once-through cooling systems would be retired at an unspecified future date.
- **Gateway** – In 2001, Mirant obtained a license to add a new 530 MW combined-cycle unit to the Contra Costa Power Plant site in Contra Costa County. Water from the once-through cooling system from the Unit 6 and 7 steam boilers would be used for cooling. Mirant's continued use of once-through cooling in the San Francisco Bay Delta was complicated by the presence of the endangered Delta smelt and five other threatened and endangered species known to occur near the cooling water intakes. A "habitat conservation plan" with the U.S. Fish and Wildlife Service was required as a condition of certification, but never completed. PG&E acquired the partially constructed project from Mirant in 2006 and announced plans to change from once-through cooling water to closed-loop towers that would use recycled water from a nearby wastewater

treatment plant. In 2007, PG&E further amended its license to switch to an air cooling system because it would be more reliable than the cooling towers with recycled water.

- **Humboldt** – PG&E filed an Application for Certification in 2007 to repower the existing 103 MW steam boiler power plant on Humboldt Bay in Eureka and replace it with Wartzilla internal combustion engines totaling 163 MW that will use radiator cooling. This innovative technology uses a modified engine of the type used in large transport ships that can run on natural gas or diesel fuel. Humboldt Bay is one the cleanest, most ecologically productive bays in California.
- **South Bay** – LS Power filed an Application for Certification in June 2006 to repower the old 703 MW steam boiler power plant on San Diego Bay and replace it with a 620 MW combined cycle power plant that will use air cooling. Due to the closed topography and limited circulation of San Diego Bay, its marine ecosystem has been susceptible to impacts from once-through cooling systems.

Analysis

This shift to repowered coastal plants using air cooling in 2006-2007 is the result of several converging legal, economic, and energy policy factors. Energy policy makers want to encourage retirement or repowering of the remaining steam boiler plants in California and encourage development of combustion turbine-based technologies that operate at higher thermal efficiencies to reduce the growth in demand for natural gas.[26] Higher efficiencies mean that less natural gas is needed to produce a MWh of electricity. All but one of the 17 coastal gas-fired power plants have steam boiler units, although Moss Landing and Haynes have been partially repowered to combined cycle technologies.

Merchant power plant owners also seek to take advantage of the steadily growing electricity market in California by investing in modern combustion turbine-based technologies that operate more economically than the older steam boiler units. As discussed in the previous section, most of the steam boiler power plants run at very low capacity factors because they are not economically competitive with the new combustion turbine combined-cycle power plants. This disparity in competitiveness will continue. The distribution utilities, or load-serving entities (LSEs), seek to purchase the lowest cost power, and the steam boilers on the coast will presumably be at a competitive cost disadvantage. However, if the coastal steam boiler power plants are considered to be peaking facilities, they may continue to be cost-competitive with new simple-cycle peaker turbines because the capital costs of the steam boilers are largely amortized while new peaker turbines have relatively high capital costs.

[26] Energy Commission *2005 Integrated Energy Policy Report*, *Energy Action Plan*, Energy Commission staff testimony to the CPUC's Long-Term Procurement Proceeding.

TABLE 17: STATUS AND KNOWN PLANS OF COASTAL PLANTS USING OTC – September 2007					
Plant Name	**Generating Technology***	**2006 Capacity (MW)**	**Location**	**Owner**	**Status and Announced Plans**
Alamitos	Steam Boiler	1970	Long Beach	AES	
Gateway (Old Contra Costa Unit 8)	Combined Cycle	0	SF Bay-Delta	PG&E	Partially completed 530 MW Unit 8 transferred to PG&E and renamed Gateway. License amendment to change from OTC to air cooling is under CEC review.
Contra Costa	Steam Boiler	680	SF Bay-Delta	Mirant	
Diablo Canyon	Nuclear	2202	San Luis Obispo County	PG&E	CPUC has approved the replacement of the steam generators which will significantly extend the life of the project.
El Segundo	Steam Boiler	670	Santa Monica Bay	NRG	CEC issued License for Units 1 & 2 to repower to 630 MW with OTC Feb 2005. Amendment to change to dry cooling filed June 2007.
Encina	Steam Boiler	965	San Diego County	NRG	NRG filed license application in September 2007 to repower Units 1-3 with a 558 MW combined cycle plant using air cooling. Units 4&5 with OTC would be retired in future.
Harbor	Combined Cycle	462	LA Harbor	LADWP	
Haynes	Combined Cycle/ Steam Boile	1606	Long Beach	LADWP	Units 3&4 replaced in 2005 re-using OTC. Units 1&2 replacement under way re-using OTC. No CEC jurisdiction.
Humboldt Bay	Steam Boiler	137	Humboldt Bay	PG&E	Application to repower with 163 MW reciprocating engine that does not require OTC under licensing review at CEC.
Huntington Beach	Steam Boiler	1013	Orange County	AES	Units 3 & 4 repowered w OTC in 2003. CEC approved post-project CEQA review and mitigation 9/06.
Mandalay	Steam Boiler	573	Ventura County	Reliant	
Morro Bay	Steam Boiler	912	Morro Bay	LS Power	The Repower License with OTC issued by CEC in 2004 will not be final until RWQCB permit is issued. Construction has not begun.
Moss Landing	Steam Boiler	1424	Monterey Bay	LS Power	
	Combined Cycle	1060	Monterey Bay	LS Power	CEC issued license with OTC in 2000. Operations began 2002.
Ormond Beach	Steam Boiler	1613	Ventura County	Reliant	
Pittsburg	Steam Boiler	1370	SF Bay-Delta	Mirant	
Potrero	Steam Boiler	363	SF Bay	Mirant	Repower Proceeding terminated 3/06. Project anticipated to be shut down when 145 MW SF Reliability Project is completed.
Redondo Beach	Steam Boiler	1310	Santa Monica Bay	AES	
San Onofre	Nuclear	2254	San Diego County	SCE/SDG&E	CPUC is considering the approval of the replacement of the steam generators which will significantly extend the life of the project.
Scattergood	Steam Boiler	803	Santa Monica Bay	LADWP	LADWP is under a consent decree to replace the project. They may seek to avoid CEC jurisdiction and will likely plan to reuse the OTC.
South Bay	Steam Boiler	709	San Diego Bay	LS Power	Application to repower to 620 MW combined cycle with air cooling under licensing review at CEC.

Notes: Total 2006 Capacity = 21,250 MW

*Includes only the units using once-through cooling. Does not include combustion turbine peakers.

Green denotes 5 plants switching to dry cooling

4 current plants in CEC licensing review for repowering without OTC (El Segundo, Humboldt, South Bay, Encina)

1 new unit in CEC licensing review using air cooling – Gateway (old Contra Costa Unit 8)

2 plants retired: Hunters Point in 2006, Long Beach combined cycle units in 2005.

Historically, fuel costs have comprised about 85 percent of the total production costs for natural gas-fired power plants. Natural gas prices have increased substantially since 2001, making generators, LSEs, and energy policy makers even more concerned about using this fuel as efficiently as possible.

The third major factor in the recent shift to air cooling on the coast is the legal and regulatory trend towards more stringent controls on once-through cooling systems. The combination of the successful legal challenges from the national Riverkeeper / Baykeeper coalition against US EPA's interpretation of the Clean Water Act, the State Water Board's development of a likely stronger rule that tracks with the Phase I regulations for new power plants seeking to use once-through cooling,[27] and continued opposition from other state and federal permitting agencies means that any new repowering applications that seek to continue using once-through cooling will face close scrutiny. Moreover, the Regional Water Quality Control Boards now have far fewer options for drafting legally defensible 316(b) NPDES permits.

The combination of these regulatory and legal factors means that planning for investment in capital-intensive projects like new and repowered power plants must incorporate the risk that applications could be substantially delayed or denied if once-through cooling is included in a proposal to repower.

CPUC Authorities Related to Once-Through Cooling

The CPUC has the authority to ensure that load-serving entities under its jurisdiction have sufficient resources to meet load growth, peak demand, and reserve margins. Through the long-term procurement program (Proceeding R-06-02-013), the CPUC works to identify increases in demand, identify risks to existing generating resources, and help ensure that LSEs under its jurisdiction secure sufficient resources to maintain resource adequacy. Future constraints on coastal power plant operations from new once-through cooling regulations are the type of long-term risk that is evaluated in the long-term procurement proceeding at the CPUC. Energy Commission staff filed testimony in the long-term procurement proceeding in 2007 reiterating the 2005 IEPR policy goal to retire the aging steam boiler fleet, including the coastal power plants with steam boilers that use once-through cooling.

The CPUC has assumed authority allowing it to approve local reliability contracts between LSEs and merchant generators. Oversight authority to maintain local reliability had been the exclusive jurisdiction of the California ISO via its Reliability-Must-Run or RMR contracts. With this authority, the CPUC can approve direct payments from utilities to operators of marginal, non-economic units to ensure that they are available for dispatch in periods of peak demand.

Modifications to the Public Utilities Code as a result of the AB 1576 legislation allows the CPUC to approve contracts between LSEs under its jurisdiction and coastal power plant operators that incorporate incremental production cost increases incurred to comply with coastal environmental

[27] Dominic Gregorio, Once-Through Cooling Rule Development Program Manager, State Water Resources Control Board, Oral Presentation before the Ocean Protection Council OTC Coordinating Committee, April 24, 2007.

regulations. The CPUC has begun a proceeding to develop standards and a regulatory process to evaluate coastal repowering projects that seek to take advantage of this potential cost recovery mechanism. This proceeding is part of the larger long-term procurement program.

These authorities and proceedings constitute the building blocks for a process that could be used to manage an orderly transition from once-through cooling to new generating and cooling technologies that feature better thermal efficiency and fewer impacts to coastal marine ecosystems.

Dry Cooling and Recycled Water Cost and Performance Issues

Power plant owners and developers have previously held the position that dry cooling or the use of recycled water in closed-loop cooling towers is an unacceptable alternative to once-through cooling on the coast because of higher costs and poor performance issues. Developers stressed this issue during the Energy Commission's licensing proceedings for the Morro Bay and El Segundo repowering cases. In the Morro Bay case, the applicant stressed that the parasitic load required to drive the cooling fans in an air-cooling tower would overly diminish the plant's efficiency and performance during peak operations. The 2nd Circuit Court of Appeals' recent decision on Clean Water Act Section 316(b) regulations also states that dry cooling is an unproven and unreasonably expensive alternative to once-through cooling.[28] In the El Segundo case, use of recycled water from the City of Los Angeles' Hyperion Wastewater Treatment Plant was rejected by the applicant because of unreasonably high costs. In both the Morro Bay and El Segundo licensing cases, Energy Commission staff found that dry cooling and recycled water were feasible alternatives to once-through cooling, although the Energy Commission licenses for both projects authorized the continued use of the once-through cooling systems.

The Energy Commission's PIER Program has been researching the cost and performance issues associated with alternative cooling since 2003. In December 2005 at the State Water Resources Control Board's second public workshop on once-through cooling regulations, PIER sponsored the research of Dr. John Maulbetsch, a noted national researcher on power plant cooling systems, their costs, and performance.

Dr. Maulbetsch presented information showing the relative cost and performance differences for new combined-cycle power plants using once-through cooling, closed loop towers with fresh water, and dry cooling.[29] For capital costs for a new 500 MW combined cycle power plant, cooling towers had 1.2 percent higher total costs than a once-through cooled plant, while dry cooling had

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[28] *Riverkeeper II* at footnote 11 states that "dry cooling costs more than ten times as much per year as closed-cycle wet cooling." The Court concluded that the marginal benefits were small and that dry cooling offered only slightly higher benefits than cooling towers at significantly higher costs.

[29] "Power Plant Cooling: What Are the Trade-Offs?" Presentation by Dr. John Maulbetsch, Maulbetsch Consulting, to the State Water Resources Control Board on December 7, 2005, Oakland, CA. Available on the State Water Board website at http://www.waterboards.ca.gov/npdes/docs/wrkshp_oakland2005/pres_jmaulbetch.pdf

12.5 percent higher capital costs (A new combined-cycle 500 MW power plant in California typically costs from $300 million to $400 million). When fuel costs were incorporated into total production costs (or normalized costs), the differences between the three cooling technologies became much smaller: cooling towers were 1.8 percent higher than once-through cooling on a per-MWh basis, while dry cooling systems were 3.3 percent higher. This reflects the fact that capital costs represented about 15 percent of total long-term operating costs, and cooling system costs were a small part of the total capital costs. Fuel costs have historically accounted for about 85 percent of total production costs on a per-MWh basis.

Dr. Maulbetsch also presented information showing that performance efficiency, also known as the heat rate, varies nominally for new combined-cycle power plants using once-through cooling, cooling towers, or dry cooling. Dry cooling caused a 0.7 percent increase in heat rates over a once-through cooled plant, while cooling towers caused a 0.37 percent increase; i.e., thermal efficiency decreased by these levels. On a summer peak demand day, a 500 MW combined-cycle power plant using dry cooling would lose about 48 MW in capacity. A plant with cooling towers would lose about 25 MW, and a plant using once-through cooling would lose about 21 MW.

The historic shift away from once-through cooling on the California coast indicates that the minor differences in cost and performance among alternative cooling technologies can be accommodated by developers and consumers.

Nuclear Plants Using Once-Through Cooling Present Special Circumstances

Nuclear power plants withdraw large amounts of water to meet a variety of plant needs. The primary water use at a nuclear power plant is for removing excess heat generated in the reactor by condenser cooling. The larger the plant the greater the amount of waste heat to be dissipated, and the greater the amount of cooling water required. California’s two operating nuclear power plants use once-through cooling. Due to their size, costs, and unique role in contributing to grid stability, fuel diversity, and resource adequacy, these two nuclear power plants present special circumstances that need to be evaluated carefully before new regulations on once-through cooling are finalized in California.

Diablo Canyon and San Onofre total 4,362 MW, which is about 7 percent of total in-state capacity. Both plants have proven to be reliable, and their baseload generation is a key element in grid reliability and voltage support. In 2006, the nuclear facilities generated 32,035 GWh, 60 percent of the coastal fleet’s production, and 13 percent of total in-state generation.

The plants represent a substantial investment from California ratepayers. The initial capital costs for the nuclear plants were high; Diablo Canyon cost PG&E and its ratepayers $5.5 billion in the 1980s. The total cost for SONGS Units 2 and 3 exceeded $4.5 billion. Both plants have recently been authorized by the California Public Utilities Commission to replace their steam generators, which would be expected to extend their operational life for decades, if their operating licenses are renewed.

In terms of environmental impacts from once-through cooling, the Diablo Canyon and San Onofre nuclear plants pose special problems. Volumetrically, these facilities withdraw substantially more sea water than the gas-fired plants because of their size and high capacity factors. Diablo Canyon is permitted to withdraw up to 2.54 billion gallons per day, while San Onofre is permitted to withdraw up to 2.58 billion gallons per day. In contrast, the largest natural gas-fired power plants on the coast – Alamitos, Haynes, and Moss Landing – are permitted to withdraw about half that amount (1.2 billion gallons per day), but in fact withdraw far less because of their lower capacity factors.

According to a study done for the Central Coast Regional Water Board, the Diablo Canyon cooling water intakes impact 93 square miles of biologically productive rocky reef habitat (an area measuring 2 miles wide by 46 miles long). The proportional mortality for nine taxa of rocky reef fishes affected by the once-through cooling system was estimated to be 10.8 percent.[30] To compensate for these environmental impacts, Dr. Michael Foster estimated that from nearly 300 to 500 acres of coastal rocky reef would need to be created to offset the Diablo Canyon impacts. About 150 acres of coastal wetlands in Southern California would be needed to offset the impacts from the San Onofre once-through cooling system.[31]

Many nuclear power plants across the country use closed-loop cooling towers for power plant cooling. Retrofitting to closed-loop cooling systems is technically feasible, though rare. For example, the Palisades Nuclear Station in Michigan retrofitted from once-through cooling to closed-loop towers. The Indian Point Nuclear Station on the Hudson River in New York has been ordered to retrofit to closed-loop towers, but the order is under appeal.[32]

Nuclear plant water usage must comply with state and local regulations. All effluent discharges from these plants are regulated under the provisions of the Clean Water Act and the guidelines and standards established by EPA and the states. Conditions of discharge for each plant are specified in its NPDES permit issued by the state or EPA. The recently suspended US EPA Phase II 316(b) regulations for existing large power plants contained a safety exemption for nuclear power plants faced with once-through cooling regulatory compliance:

> "If you demonstrate… based on consultation with the Nuclear Regulatory Commission that compliance with this subpart would result in a conflict with a safety requirement established by the Commission, the Director must make a site-specific determination of best technology available for minimizing adverse environmental impact that would not result in a conflict with the Nuclear Regulatory Commission's safety requirement."[33]

The Court affirmed in *Riverkeeper II* that US EPA had appropriately addressed the nuclear safety issue in *Riverkeeper I*, stating "We defer to the EPA's determination that this compliance alternative

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[30] Described in the State Water Board's Proposed Statewide Policy on 316(b) Regulations, page 21.
[31] Acreage replacement estimates derived using the Habitat Production Foregone methodology as described in *Issues and Environmental Impacts Associated with Once-Through Cooling*, Energy Commission Staff Report.
[32] The Palisades and Indian Point examples are described in US EPA's Technical Development Document, which was prepared in support of the Phase II 316(b) Rulemaking.
[33] 40 C.F.R. 125.94(f) – Suspended in July 2007.

ensures that any safety concerns unique to nuclear facilities will prevail over application of the general Phase II requirements."[34] Even though the Phase II Rule was suspended, it is anticipated that US EPA's nuclear safety provision will be included in the Phase II rulemaking scheduled for October 2007.

The State Water Board also recognized the unique safety issues associated with California's nuclear facilities in its 2006 proposed policy on 316(b) Regulations and proposed the following language:

> "If an existing nuclear power plant demonstrates that implementation of operational and/or technological measures for the reduction of impingement and entrainment would conflict with safety requirements instituted by the Nuclear Regulatory Commission, the upper end of the performance standards for impingement and entrainment may be met using any combination of operational or structural controls and restoration measures."

This proposal to allow for restoration measures as part of the BTA is now problematic due to the Second Circuit Decision, which determined that offsite restoration is not a BTA compliance option for 316(b) regulations.

2007 Integrated Energy Policy Report Workshop on Nuclear Power Issues

At the June 28, 2007 IEPR Committee Workshop on Nuclear Power Issues, several of the participants discussed the relation of once-through cooling environmental issues and nuclear power plant safety issues.

Dr. Samson Lee, acting deputy director of the Division of Reactor Safety in the Region IV Office for the Nuclear Regulatory Commission (NRC), said that issues relating to the impact of thermal discharge of the once-through cooling in the NRC licensing process are deferred to the state because the state issues the National Pollutant Discharge Elimination System (NPDES) permit through the Clean Water Act.[35]

Energy Commissioners John Geesman and Jeffrey Byron asked Dr. Lee to confirm that the NRC will to defer to the states regarding the issuance of the NPDES permit for all plants licensed by NRC. Dr. Lee said that the NRC made it clear that they would defer to the states.[36]

Commissioner Geesman referred to the Riverkeeper II Second Circuit Court decision and stated that his interpretation of the decision was that NRC's safety requirements would prevail when in conflict with the environmental requirements of the NPDES permit. Asked to elaborate how he envisions the NPDES permit deferral process working, Dr. Lee stated that "there is a certain safety

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[34] Riverkeeper II Decision.

[35] June 28th Nuclear Workshop Transcripts at page 20. http://www.energy.ca.gov/2007_energypolicy/documents/2007-06-25+28_workshop/2007-06-28_TRANSCRIPT.PDF

[36] June 28th Transcript at page 45.

requirement that the plant needs to meet. By meeting the safety requirement, but if it cannot meet the environmental impact [of] the [dis]charge permit then they can not operate."[37]

Commissioner Geesman summarized the discussion by stating: "So would it be correct for me to conclude that a state has a pretty free range of discretion in its NPDES decision making as long as it does not come into conflict with one of your safety requirements."[38]

[37] June 28th Transcript at page 46, lines 7 to 12. The quote is somewhat ambiguous in the transcript. The verbatim transcription is: "DR. LEE: The deferral, the way I see it is that this deferral relates to the environmental impact. For safety there is a certain safety requirement that the plant needs to meet. By meeting the safety requirement but if it cannot meet the environmental impact like the, the charge permit then they can not operate."

[38] June 28th Transcript at page 46.

CHAPTER 5: Biological Resources

Potential Impacts on Biological Resources

- **Impacts from Solar Thermal Development:** The development of numerous large solar projects on public and private land has the potential to impact protected species and sensitive habitat and is expected to require off-site habitat compensation and other mitigation. Large solar projects have been proposed in a range of locations, from graded former agricultural fields to undisturbed desert habitat. Project sites without sensitive species or reduced habitat value (such as graded agricultural fields) will result in fewer impacts to biological resources.
- **MOU with Bureau of Land Management:** The Energy Commission and U.S. Bureau of Land Management (BLM) have developed a Memorandum of Understanding (MOU) to coordinate state and federal environmental review and establish consistent mitigation requirements for the large solar projects anticipated in the California desert. Current BLM data show a total of 38,488 MW in new lease applications for solar thermal and solar PV energy projects. The acreage identified in the lease applications total more than 525,000 acres (820 square miles). Based on Energy Commission staff data from recently filed solar thermal projects (requiring 8 acres per MW), about 308,000 acres of public land could be dedicated to solar projects, with additional large solar projects likely to occur on private lands.

Introduction

The *2001, 2003, and 2005 Environmental Performance Reports* (CEC 2001, 2003, 2005) made several findings that are still relevant:

- Many power plants and ancillary facilities were built before environmental regulations required project developers/owners to meet current environmental standards. As a result, unmitigated impacts have been perpetuated.
- While most of the original steam-boiler power plants were in coastal areas where once-through cooling using ocean or bay water was available, the vast majority of new combined-cycle plants are inland and do not use once-through cooling. The continuing use of once-through cooling at existing coastal power plants will perpetuate impacts to the marine environment.
- Habitat loss from electricity infrastructure is low compared to other impacts such as urbanization and agricultural land conversion.
- As the state expands renewable power supplies to meet the state’s Renewable Portfolio Standard, the biological resource impacts will occur due to increased solar and wind energy development.

Potential Impacts of Renewable Energy Development on Biological Resources

Implementation of California's Renewables Portfolio Standard (RPS) requires that electricity retailers increase the amount of electricity from renewable resources. In addition to wind energy, eligible technologies include solar photovoltaic, solar thermal-electric, geothermal, waste-to-energy, and small hydroelectric technologies. Overall, solar thermal, wind energy, and geothermal projects dominate the contracts signed by the utilities since 2002 for new RPS-eligible generating capacity.[41]

The California Independent System Operator (California ISO) Controlled Grid Generation Queue reflects projects that have or are in the process of interconnecting to the portion of the California grid controlled by the California ISO (CA ISO 2007). The queue provides a near-term estimate of proposed capacity by electricity generation technology, although some projects have online dates as far in the future as 2013. The queue provides one perspective on the potential for anticipated growth of renewable energy resources, as shown in Table 18.

A second perspective shown in Table 18 is provided by examining lease applications that the BLM has received for solar projects on federal land. Through August 15, 2007, the BLM had received energy applications for solar thermal and solar PV projects totaling 525,000 acres, or 820 square miles. Such lease applications are generally for land areas greater than what is actually needed for the energy facility.

The Energy Commission has received three applications for new solar thermal or hybrid gas-solar projects plus a Plan of Development for a fourth large solar thermal project. Another eight solar thermal projects have been announced. Filed or planned solar thermal projects at the Energy Commission total 4,070 MW. Based on the data from the most recently filed projects, Energy Commission staff believes that the figure of 8 acres per MW best represents the actual land requirement for this technology. Therefore, the 4,070 MW of solar thermal capacity filed or planned at the Energy Commission would require 32,560 acres. When this figure is applied to the total 38,488 MW capacity of the BLM applications, the actual land required for the energy facilities drops to 307,904 acres from the BLM lease application total of 525,000 acres.

The total desert area of Southeast California measures about 35,000 square miles. Using the Energy Commission staff estimate of 8 acres per MW, about 1.4 percent of the total desert could be used for solar thermal and solar PV generating technologies if all 38,488 MW of capacity proposed at the BLM were to be constructed.

Table 18: Potential Renewables Development Acreage

[41] The entire database can be viewed at **http://www.energy.ca.gov/portfolio/IOU_CONTRACT_DATABASE.XLS**

Technology Type	Acres per MW[1, 2]	Cal ISO MW Estimate	Cal ISO Acreage Estimate [4]	BLM Applications (MW)	BLM Applications (Acres)	CEC Applications (MW)	CEC Applications (Acres)
Wind	5.4	15,783	85,200	598	Note 5		
Geothermal	0.17	562	95				
Solar thermal	8.0	10,304	82,432	28,556	400,536	4,070	32,560
Solar PV [3]	13.3	3152	42,030	9,334	124,464		
Total		**29,801**	**209,757**	**38,488**	**525,000**	**4,070**	**32,560**

Sources: California ISO Controlled Grid Generation Queue, 2007
U.S. Bureau of Land Management, compiled from field office permit applications as of August 15, 2007.
California Energy Commission, Siting Program Data from AFCs and Pre-Filing Conferences with applicants.

Notes [1] Wind and geothermal acres per MW drawn from *2005 Environmental Performance Report*. Solar PV calculated from BLM data (total reported acres / total reported MW).

[2] Solar thermal acreage estimate of 8 acres per MW figure is derived from 3 recently filed applications at the California Energy Commission. Energy Commission staff believes this figure is the most accurate estimate available to date for the acreage required for new solar thermal projects. Previous estimates have ranged from 5 to 14 acres per MW.

[3] Industrial-scale solar PV development in rural desert areas is just beginning and little data on the precise land requirements are available. The 13.3 acres per MW figure is derived from the BLM lease applications. As with solar thermal, the actual land required for installation of the solar PV generating equipment is likely to diminish as projects mature to the development phase.

[4] Derived from acres per MW in Column 1.

[5] The BLM data report for August 15, 2007 shows a total of 493,000 acres encumbered by wind energy applications, but only 598 MW. Many wind energy firms have applied for energy applications without designating the MW.

Power generation technologies in California vary in how much acreage is required to produce a unit of power. In many cases, the potential for direct impacts to biological resources from the construction of a generating facility is proportional to the amount of land required for that facility. The following chart (Figure 12) depicts an approximation of the amount of acreage required for 100 MW of electrical generating capacity. It depicts the land requirements for the power plant site and does not represent the impacts of transmission lines, other appurtenant facilities, or fuel mining and processing (i.e., the entire fuel cycle). The acreage figures are taken from the *2005 Environmental Performance Report* (CEC 2005), except for the solar technologies, which have been updated and are described in more detail later. There is a significant difference between the acreage required for a relatively compact power plant using a high energy-density fuel (natural gas, nuclear, geothermal) and the acreage required to develop the same generating capacity using solar (thermal and photovoltaic), wind, or hydroelectric generation.[42]

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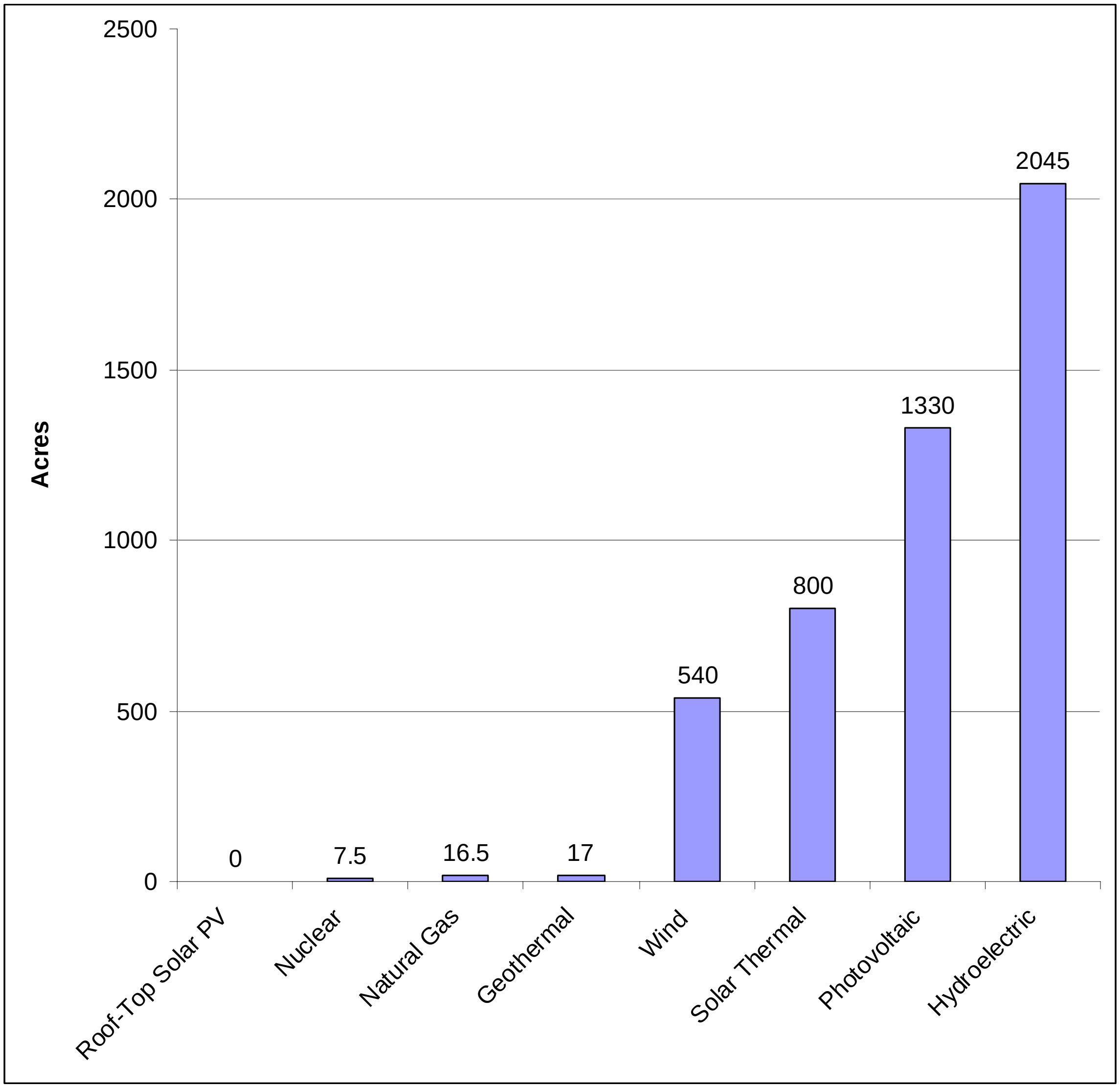
[42] Energy Commission staff uses the acreage of the actual power plant footprint (as measured by the facility "fence line") to determine the biological resource impacts to terrestrial and aquatic habitats for the Environmental Performance Report series. This method conforms to the original legislative intent and to the standard practices of the California Environmental Quality Act. This method is different from life cycle or full-fuel analysis methods, when all the environmental impacts from initial mining and processing of the fuel, fuel transport, power plant construction, power plant operations and power plant decommissioning are tallied and quantified. Life cycle scale analyses for the California power generation fleet would require data on fuel mining, processing and transport from throughout North America and Asia.

Figure 13: Average Amount of Land (in Acres) Used to Produce 100 MW for California Power Plants



Source: Energy Commission staff. Updated from 2003 and 2005 Environmental Performance Reports (based on Siting Program and Environmental Performance Report data sets). Natural gas, geothermal and nuclear acreage figures based on data from California facilities. Solar Thermal figure based on 3 representative solar thermal projects filed or announced at the Energy Commission in 2007. Hydroelectric acreage includes reservoir surface acreage.

Based on the amount of land needed to produce 100 MW of electricity at a California power plant, the most efficient use of acreage (and the lowest amount of lost habitat) is for a centralized power plant such as nuclear, natural gas, or geothermal. By comparison, the least efficient use of acreage (habitat) is hydroelectric (2045 acres), solar photovoltaic (1400 acres), and solar thermal (800 acres). Rooftop solar photovoltaic is by definition the most efficient use of habitat acreage at 0 acres per 100 MW because the panels are installed on urban and suburban rooftops.

Decommissioning

As a project reaches the end of its economic life, ceases electricity generation, or is retired, the project continues to impact the land and habitat unless steps are taken to remove project infrastructure and restore habitat. While some permitting agencies have specific facility closure requirements, closure can represent a potential issue for some projects, especially when unforeseen circumstances, such as bankruptcy, arise.

As an example, the Energy Commission licensed the Luz SEGS Unit 10 project in 1990, a solar thermal project proposed by Luz near Harper Lake in San Bernardino County (CEC 1990). The Energy Commission required that $100,000 be set aside for a decommissioning fund during the first year of commercial operation. The project area was graded, foundation piers poured, fencing constructed, and then the project owner went bankrupt. Unit 10 was never completed, the decommissioning funds were not collected, and the fencing and foundations remain on the one-square mile project site. The BLM, Alameda and Kern Counties have experienced comparable problems with abandoned wind turbines, and have incorporated provisions to require removal of inoperative equipment into the leases or permits they issue to wind electric generators.

The decommissioning of solar power plants and habitat restoration of project sites is of particular concern in desert areas, as the resulting disturbed desert habitats recover very slowly, extending the species impacts well beyond the life of the project. A closed and non-operational project presents an ongoing loss of habitat, so removal of a closed project and restoration of the project site may ultimately benefit sensitive biological resources, including protected species. As technological and economic conditions change, awareness of the need to plan for decommissioning, in particular for large solar projects in the California desert, could help prevent an accumulation of inoperative projects and help to minimize biological resource impacts.

Wind Energy

Wind energy projects impact bird and bat populations and impact terrestrial biological resources from construction of turbine pads and service roads. Approximately 540 acres are required to produce 100 MW at a wind farm. As discussed in the 2005 EPR (CEC 2005), wind farms still provide some habitat for local wildlife species. Wind energy projects do not fall under the siting authority of the Energy Commission, but implementation of the voluntary *California Guidelines for Reducing Impacts to Birds and Bats from Wind Energy Development* (described in Chapter 5) will help CEQA lead agencies make informed decisions regarding new wind energy projects.

Geothermal Energy

Geothermal energy resources exist in several areas of the state and additional development is anticipated in Imperial County, Lake County, and the northeastern and north-central portions of California. These new projects are likely to be constructed in previously undisturbed habitat. Geothermal power plants are compact when compared to a solar thermal or a photovoltaic project, although sensitive biological resources have the potential to occur in the areas where geothermal power plants may be proposed. Staff anticipates that mitigation measures, including habitat compensation, will help to minimize and offset impacts to biological resources from these projects. The Salton Sea Geothermal Unit #6 Project, an Imperial Valley geothermal project, was approved by the Energy Commission in 2003 but has not been built. No geothermal projects are currently under review with the Energy Commission.

Solar Energy

Solar Photovoltaic

Photovoltaic (PV) projects use panels that generate electricity directly from sunlight. The Energy Commission does not have licensing jurisdiction for solar PV development and projects are licensed by local government or federal land agencies. PV electrical generation does not require a stand-alone power plant and has generally been integrated into existing building roof-tops or other developed areas, which causes no impacts to biological resources. By contrast, when a stand-alone PV system is constructed on an undisturbed site, site grading and project maintenance will eliminate nearly all habitat value. For example, the 11 MW GE / Powerlight PV plant in Serpa, Portugal, requires 143 acres (13 acres per MW of generation capacity) (Solarbuzz 2007). The BLM has received energy applications for nearly 10,000 MW of solar PV projects on public land since 2005 that would average approximately 14 acres per-MW of capacity. No large utility-scale PV projects have yet been constructed in California.

There is potential for new commercially developed solar concentrating PV technologies, which use concentrating mirrors or lenses to focus sunlight on high-efficiency PV cells. This technology requires less land per-MW than solar PV and may reduce the required footprint by up to 50 percent, which could reduce the impacts to sensitive species and their habitat by a proportional amount.

Solar Thermal

Solar thermal power plants transform heat from the sun into mechanical energy, which is then used to generate electricity. The shape and structure of the solar collectors/reflectors varies depending on the technology employed. Parabolic trough collectors use long parabolic mirrors that focus the sunlight on a central tube containing a heat transfer fluid, which is circulated back to a central power plant that houses a generator. Similarly, solar tower projects use a field of tracking mirrors that focus the sun on a central tower, where the heat transfer fluid is heated and then used to power electrical generation. A third technology, which is not fluid based, uses a field of independently tracking parabolic mirrors, each of which focus the sunlight on its own Stirling-cycle engine, which drives a small attached generator. Some of these facilities use conventional gas-fired steam boilers to generate supplemental electricity. The use of water for evaporative cooling can place a significant strain on limited water resources in arid areas and could potentially impact sensitive biological resources.

The amount of acreage (habitat) required for each type of solar thermal technology varies. The existing Harper Lake parabolic trough projects in San Bernardino County impacted 5 acres for every MW produced, while the Victorville 2 hybrid gas-solar project will require 250 acres for the array of solar troughs that will generate 50 MW of capacity (5 acres per MW). The recently filed Ivanpah Solar Electric Generation Station featuring the BrightSource solar tower technology will ultimately total 400 MW and require 3,400 acres (8.5 acres per MW). The Stirling Solar Project has filed a Development Plan with the BLM and Energy Commission and could ultimately total 4,275 MW and require 32,600 acres (7.6 acres per MW). In summary, solar thermal technologies range from 4.8 to 9 acres per MW. Energy Commission staff believes that the average figure of 8 acre per MW best represents the current project descriptions filed with the Energy Commission. Given that some of these power production figures represent proposed performance, this range is expected to vary when additional applications are filed at the Energy Commission.

The California ISO Queue provides one range of projections of the land that could be impacted from solar thermal projects, as shown in Table 18.

Examining the solar energy proposals that the BLM has received for public land provides a different perspective of the scale of the acreage that may be dedicated to solar projects. The National Energy Policy Act of 2005 encourages the development of renewable resources, and the BLM has instituted a policy to facilitate environmentally responsible commercial development of solar energy projects on public lands. Recent discussions with the BLM, which is responsible for leasing some public land for energy development, has indicated that more than 50 applications for development of solar projects on public land have been filed (BLM 2007). If all of these projects are actually built, over 400,000 acres (625 square miles) would be developed for solar energy development projects on public land in California. Figure 13 shows the location of the solar energy project applications received by BLM in southeast California

Solar projects vary in the amount of acreage impacted, but when considered together, these projects will impact thousands of acres and square miles of habitat, so habitat compensation could become a significant issue. The habitat compensation required to offset this habitat loss will depend on whether the acreage is sensitive species habitat and the nature of the ground disturbance. The ratio of impacted acreage to the amount of habitat compensation acreage varies depending on the resource impacted. Projects on disturbed land (not industrial) may be required to provide habitat compensation at a ratio of one-half acre of compensation habitat for every acre impacted (0.5:1), while projects that impact higher quality sensitive species habitat are likely to require the preservation of an equivalent habitat at a 1:1 or higher ratio.

Solar projects that are proposed for construction in previously impacted areas will have reduced impacts to biological resources when compared to undisturbed habitat. Solar projects are being considered for sites previously used as irrigated alfalfa farms, which have already had the native vegetation removed and been graded. These previously developed sites will have reduced impacts to biological resources when compared to an undisturbed site that would require grading and removal of existing plant and animal populations.

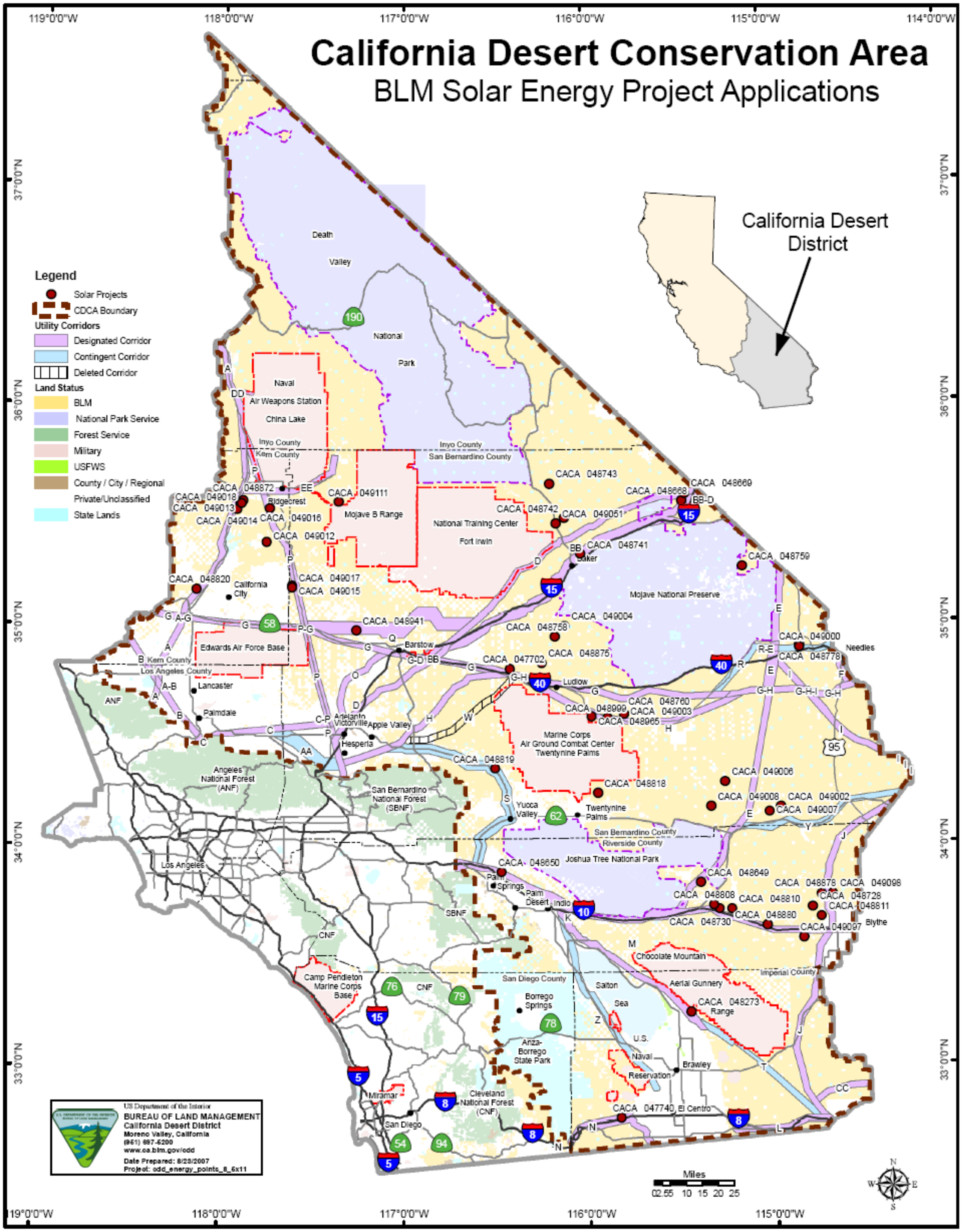
When the Energy Commission licensed the LUZ SEGS solar thermal projects at Kramer Junction and Harper Lake (San Bernardino County) in the 1980s and 1990s, the U. S. Fish & Wildlife Service, CDFG, and Energy Commission required a habitat compensation ratio of 5:1 because the projects impacted high-quality protected species habitat. If compensation ratios at these levels are required for some of these new, very large solar projects then identifying sufficient compensation acreage may be a significant concern. Thousands of acres of large solar projects could ultimately require protection of hundreds of miles of compensation habitat. The BLM has already indicated large tract of public lands identified as Desert Wildlife Management Areas and Wilderness Areas as off-limits to energy development, which further restricts where projects can be built and where habitat compensation can be considered.

The California desert has many specialized and endemic species, including a number of state and federal protected species. Two species of particular concern for the development of solar thermal projects are the state and federal threatened desert tortoise (*Gopherus agassizii*) and the state threatened Mohave ground squirrel (*Spermophilus mohavensis*). Both species range across much of the land under consideration for development of solar power in the Mojave Desert. The desert tortoise has declined across much of its range and faces ongoing threats from development, predation, and human impacts (West Mojave Plan HCP, 2005). The Mohave ground squirrel is also threatened by habitat loss, impacts from urbanization, and increasing levels of disturbance (West Mojave Plan HCP, 2005). Constructing these large solar projects will eliminate habitat and create barriers to species movements across the landscape. Other sensitive species with very localized distributions, such as the flat-tailed horned lizard (*Phrynosoma mcallii*), or certain sensitive plants may also be adversely impacted by these large solar projects, which can isolate populations and limit opportunities for colonization.

Cumulative habitat impacts from the development of these large solar projects will be a major concern to permitting and wildlife agencies. A significant cumulative impact may result when an incremental impact of one project is added to the impacts from other existing or reasonably foreseeable future projects and become cumulatively considerable. Cumulative habitat loss and fragmentation represent concerns to biological resources in the California desert, as development of multiple projects can isolate sensitive species populations on smaller patches of habitat. These isolated populations may lack genetic or habitat diversity, resulting in increased risk of disease, predation, or other disturbance and diminishes or eliminates the viability of that localized population. In arid environments such as the California deserts, localized extirpations do occur during low-rainfall years for some species, so many large solar projects could potentially present permanent barriers to recolonization and rare sensitive species populations may not be able to overcome these problems when there are increased habitat losses.

Impacts to desert ecosystems can be reduced if large solar projects are developed in lower quality habitat areas such as tracts of abandoned irrigated agricultural land. Energy Commission staff are working with BLM, CDFG, USFWS, the counties, and solar project owners to develop appropriate protocols and mechanisms for decommissioning of solar projects and restoration of disturbed project-site habitat.

Figure 14: Location of BLM Solar Energy Applications in California



California Energy Commission - Bureau of Land Management Memorandum of Understanding to Coordinate State and Federal Permitting and Environmental Reviews

The potential for numerous solar thermal energy projects sited on public land has prompted Energy Commission and BLM staff to develop a Memorandum of Understanding (MOU) to facilitate the joint National Environmental Policy Act (NEPA) and California Environmental Quality Act (CEQA) analysis these projects must undergo.

The development of renewable energy resources to meet the state's RPS goals will also require the construction of additional transmission infrastructure to convey this power from the often remote areas it will likely be generated in to where it is needed. These infrastructure improvements will also likely require close coordination with BLM and other state and federal agencies. The construction of transmission lines represents a potential roadblock to the development of renewable resources, and the extended timeframes for obtaining rights-of-way and permitting transmission projects could delay the development of renewable resources. These future transmission projects also could impact biological resources by eliminating and fragmenting habitats.

The large numbers of projects proposed for development on public land, some of which will be permitted by the Energy Commission, will require close cooperation between the Energy Commission and the BLM. Solar projects as well as other renewable energy projects will also require additional improvements to the state's transmission infrastructure, with the potential for significant impacts to biological resources. Both agencies should continue close coordination to ensure timely permitting and protection of environmental resources.

Habitat Losses from Power Plant Development Under Energy Commission Jurisdiction

Recent power plant development and habitat losses

California's diverse topography and favorable climate have contributed to the proliferation of rich and varied biological communities with many specialized and unique species, many of which are known only from California and are state or federally protected. These species are often adapted to specific habitats and as a result may have very localized populations, which can be sensitive to direct and indirect impacts by energy development. Mitigation, including habitat compensation, may reduce impacts, but the additive habitat loss and fragmentation of natural landscapes may also represent cumulative impact concerns for these protected species.

Since 1996, 34 power plants projects totaling 12,376 MW were permitted by the Energy Commission and are constructed and operating or are currently under construction. Approximately 1,288 acres were impacted by these projects for the construction of the new power plants. Impacts beyond the fenceline of the project do impact biological resources for some projects, and additional compensation was required to offset those impacts. Some off-site impacts that resulted in additional habitat compensation are wetland impacts, protected species impacts, nitrogen deposition on sensitive habitats, and once-through cooling. The Roseville Energy Park project required additional compensation for impacts to wetlands, and Sunrise, Sunrise II, La Paloma, and Pastoria required compensation for impacts to protected species. The Metcalf Energy Center, Von Raesfeld Combined Cycle (Pico), and Los Esteros Critical Energy Center were shown to have nitrogen deposition impacts on sensitive habitats, which resulted in additional habitat compensation. Once-through cooling can impact coastal habitats that are the cooling water source, and can affect many organisms through impingement, entrainment, and thermal discharges. Recently, the Huntington Beach Repower Project was required to fund restoration 66 acres of tidal wetlands as compensatory habitat for the biological impacts from its once-through cooling system.

The following table summarizes those projects and notes the acreage of any required habitat compensation.

Table 19: Acreage Impacts of New Power Plants and Habitat Compensation Acreage

Power Plant Name	Site Description	Acres Impacted	Compensation Acres	Year Online	County	Online MW
Hanford Peaker	industrial & agricultural	6.10	27.4	2001	Kings	95
Los Medanos District Energy Facility	industrial	12	0	2001	Contra Costa	555
Sunrise	industrial & saltbush scrub	82	155.1	2001	Kern	320
Sutter Power Project	grasslands & vernal pools	16	11	2001	Sutter	540
Wildflower-Indigo	coastal sage scrub	10	0	2001	Riverside	135
Wildflower-Larkspur	agricultural	8	0	2001	San Diego	90
Delta Energy Center	brownfield	30	1.48	2002	Contra Costa	861
Gilroy Energy Center	industrial & agricultural	7	0	2002	Santa Clara	90
Henrietta Peaker	industrial & agricultural	20	9.3	2002	Kings	96
King City Energy Center	brownfield	6.7	0	2002	Monterey	50
Moss Landing	industrial	25	183[43]	2002	Monterey	1060
Valero	industrial	2	0	2002	Solano	51
Blythe I	desert scrub	76	77.15	2003	Riverside	520
Elk Hills	industrial & natural	66.46	101.94	2003	Kern	500
High Desert	brownfield[44] & natural	461.2	859	2003	San Bernardino	750
Huntington Beach Units 3 & 4	industrial	0[45]	66[46]	2003	Orange	225
La Paloma Units 1 – 4	Saltbush scrub	23	246.5	2003	Kern	1124
Los Esteros Critical Energy Center	industrial	18	40	2003	Santa Clara	180
Sunrise II	industrial	0	237.4[47]	2003	Kern	265

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[43] Habitat acreage for impacts to coastal ecosystem from once-through cooling project built on existing power plant site.
[44] Brownfield means that project site was previously developed.
[45] Only power plant units were replaced, and no acreage was impacted.
[46] Funds paid to restore this acreage of tidal wetlands to mitigate impacts from once-through cooling.
[47] Sunrise II is on the Sunrise site - habitat compensation primarily for pipeline impacts.

Power Plant Name	Site Description	Acres Impacted	Compensation Acres	Year Online	County	Online MW
Woodland II	brownfield	0	0	2003	Stanislaus	80
Kings River Peaker	industrial	9.5	0	2005	Fresno	97
Magnolia	industrial	6.4	0	2005	Los Angeles	328
Metcalf Energy Center	disturbed & serpentine grassland	12	131[48]	2005	Santa Clara	600
Pastoria Phase 1	grasslands & saltbush scrub	160.6	245.2	2005	Kern	250
Vernon - Malburg	industrial	3.4	0	2005	Los Angeles	134
Von Raesfeld Combined Cycle (Pico)	industrial	2.85	0	2005	Santa Clara	147
Mountainview	industrial	18.7	0	2006	San Bernadino	1056
Palomar Escondido	agricultural & coastal sage scrub	14.6	21.6	2006	San Diego	546
Ripon	industrial	8	0	2006	San Joaquin	95
Riverside Energy Resources Center	industrial	12	12	2006	Riverside	96
SMUD Combined Cycle	grasslands, wetlands	51.85	53.9	2006	Sacramento	500
Walnut Energy Center	agricultural & industrial	18	0	2006	Stanislaus	250
Roseville Energy Park	grasslands & vernal pools	16.1	21	2007	Placer	160
Gateway Generating Station	industrial	20	0	2009	Contra Costa	530
Otay Mesa	grassland & coastal sage scrub	64.6	35.9	2009	San Diego	590
Totals		1288 acres	2469.87 acres			12,376 MW

Source: Energy Commission Siting Database

Ten power plant projects licensed by the Energy Commission have been constructed since the 2005 *Environmental Policy Report*, and seven of those facilities were constructed in industrial or existing power plant settings with limited or no habitat value. The re-use of previously impacted land to site power plants can dramatically reduce the direct impacts to biological resources, also reducing

[48] Majority of mitigation acreage to mitigate indirect and cumulative impacts from NO_X emissions.

or eliminating the need for habitat compensation. In contrast, projects that did impact biological resources were often required to purchase and preserve habitat to offset those impacts to mitigate impacts to California's sensitive biological resources. In addition, project developers were also required to provide a suitable endowment for the perpetual care of the compensation habitat.

Chapter 6: California Guidelines for Reducing Impacts to Birds and Bats from Wind Energy Development

Californians have high expectations for their state's renewable energy programs. California's current Renewables Portfolio Standard calls for 20 percent of the state's energy to come from renewable resources by 2010, with expansion to 33 percent by 2020. California has ample wind resources, and wind energy is expected to play a vital role in meeting RPS goals. Wind turbine technology is increasingly efficient and cost-competitive and could increase from current levels of 2,202 MW to 10,000 to 15,000 MW by 2020.[51]

Californians have equally high expectations for protection of the state's diverse bird and bat populations. As described in the *2005 Integrated Energy Policy Report* and *Environmental Performance Report*, some wind turbines and wind farms can cause high levels of mortality to bird and bat populations. To help meet both of these expectations, the Energy Commission has collaborated with the California Department of Fish and Game (CDFG) to develop the voluntary *California Guidelines for Reducing Impacts to Birds and Bats from Wind Energy Development.* The *Guidelines* will encourage the development of wind energy in the state while striving to minimize impacts to birds and bats.

The federal government and many states have begun to recognize that rapid expansion of wind energy development has not been accompanied by coordinated planning to assess the impacts of such development on birds and bats. The absence of governmental guidance for evaluating, planning, siting, and regulating wind energy development has created inconsistencies in the quality of environmental review and assessment on local, regional, and national levels. Such inconsistencies and lack of planning have been identified as significant issues by the National Research Council in its May 2007 report[52] on the environmental impacts of wind energy projects, and by numerous witnesses at a recent House Subcommittee Oversight Hearing.[53] The U.S. Fish and Wildlife Service (USFWS) tried to remedy this lack of guidance by issuing voluntary *Interim Guidelines to Avoid and Minimize Wildlife Impacts from Wind Turbines* in 2003, but the guidelines did not gain full support from industry, non-governmental conservation organizations, and all states (Goodwin 2007). In August 2006, the USFWS initiated a collaborative approach to draft guidelines in accordance with the Federal Advisory Committee Act.

California has been a leader in identifying the need for guidelines to address wind energy impacts to wildlife and in taking action to create them. The Energy Commission's *2005 Environmental Performance Report* discussed the issue of bird collisions with wind turbine blades. In the *2005*

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[51] The Scenario Modeling Project for the *2007 Integrated Energy Policy Report* examines reductions in greenhouse gas emissions from various energy efficiency and renewables development strategies. The High Renewables Case 4b would add 10,000 MW of new wind by 2020. The California Independent System Operator's Transmission Interconnection Queue currently shows over 15,000 MW of potential wind development in California.

[52] Environmental Impacts of Wind-Energy Projects. 2007. Committee on Environmental Impacts of Wind Energy Projects, Division of Earth and Life Sciences, National Research Council of the National Academies.

[53] "Gone with the Wind: Impacts of Wind Turbines on Birds and Bats" – testimony before the Subcommittee on Fisheries, Wildlife, and Oceans, U. S. House of Representatives Committee on Natural Resources, 1 May 2007.

Integrated Energy Policy Report, the Energy Commission recommended the development of statewide protocols to address avian impacts from wind energy development. Following the report's recommendation, the *Guidelines* effort originated in January 2006 at the "Understanding and Resolving Bird and Bat Impacts" conference in Los Angeles. Many participants at the conference encouraged the Energy Commission and CDFG to collaborate, with input from all interested parties, to establish voluntary, statewide guidelines.

On May 24, 2006, the Energy Commission adopted an Order Instituting Informational proceeding that assigned the task to the Energy Commission's Renewables Committee.[54] To assist Energy Commission and CDFG staff in this endeavor, the Renewables Committee established a science advisory committee and solicited suggestions from stakeholders on how to incorporate public input into the guidelines development process. As a result, the Energy Commission has hosted several public workshops throughout the state and solicited written comments on draft *Guidelines* to make sure all interested parties have input. The extensive public participation provided a forum for the wind industry, environmental groups, and other non-governmental organizations to provide information, express their concerns, and enable staff from the Energy Commission and CDFG to make numerous improvements to the *Guidelines.*

The *Guidelines*' purpose and goal is to provide recommendations on methods to assess bird and bat activity at proposed wind energy sites, design pre- and post-permitting monitoring plans, and develop and implement impact avoidance, minimization, and mitigation measures. Both wind energy proponents and bird and bat populations will benefit if agencies that permit wind energy development projects apply the methods recommended in the *Guidelines*. Using the protocols outlined in the *Guidelines* will promote scientifically sound, cost-effective study designs; produce comparable data among studies within California; allow for analyses of trends and patterns of impacts at multiple sites; and ultimately improve the ability to predict and resolve impacts locally and regionally.

A step-by-step implementation guide opens the *Guidelines* and highlights the recommended process and standardized protocols for successfully gathering information useful to the environmental review and the permitting process. The remaining chapters provide greater detail as well as the scientific background and rationale for the recommended methods. These methods describe the steps necessary to assess bird and bat use at a potential wind energy site; estimate impacts; develop mitigation measures to satisfy the California Environmental Quality Act, and address state and federal wildlife protection laws; and monitor bird and bat fatalities once the project has begun operation. The closing chapter recommends reporting bird and bat fatality and use data to a public, online repository, which will be used by Energy Commission staff to indirectly track and collect information on the *Guidelines'* usage for future *Environmental Performance Reports.* For current information, please visit the Energy Commission's website at www.energy.ca.gov.

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[54] California Energy Commission Docket 06-0II-1. Interested parties can find details on the Order Instituting Informational proceeding, comment letters, and summaries or transcripts of past workshops on the Energy Commission Web site, <www.energy.ca.gov/renewables/06-OII-1/>.

The primary biological resource concern with wind energy are impacts to bird and bat populations from collisions with the wind turbines. Impacts to raptors in the Altamont Pass in Alameda County and to bats in Solano County have raised concerns and highlighted the need for additional guidance on the best methods and research techniques for understanding the bird and bat populations in a specific wind resource area through minimizing and mitigating identified impacts. Impacts to bird and bat species are difficult to characterize or assess because species and site specific impacts vary and have not been assessed or reported consistently. Also, the ongoing nature of the wind energy impacts creates a unique challenge in quantifying impacts to individual species and determining suitable mitigation.

The development of increased wind generation capacity will result in the construction of additional wind turbines, which will require new turbine pads and service roads. However, given the spacing requirements of between one and three times the rotor diameter (50 to 600 feet) between turbines, and from eight to 12 diameters (400 to 2350 feet) between rows, the footprint of a wind power development represents a small portion of the area of the project (CEC 2005). The impacts of the wind turbines' footprints on sensitive terrestrial biological resources should be considered when a wind project is permitted.

Wind energy development licensing does not fall under the siting authority of the Energy Commission, but rather under the local permitting authority such as a city, county, or municipal utility. The *Guidelines* encourage the use of specific procedures and practices that will assist wind energy developers and permitting agencies in assessing bird and bat activity at project sites, minimizing and mitigating impacts on birds and bats, and reporting field data to the CDFG and Energy Commission. The *Guidelines* suggests study methods and pre- and post-permitting monitoring protocols that will help standardize the understanding of bird and bat activity levels at project sites, as well as impacts to those bird and bat species from the operating turbines. The document encourages wind energy project developers to submit data to a central CDFG repository, which will allow for monitoring and analysis of the use and success of the *Guidelines,* as well as inform the ongoing scientific understanding of bird and bat interactions with wind turbines. The field information may also make it possible to have a discussion of impacts in a wind resource area or region and analyze cumulative impacts of California's wind energy development on bird and bat populations.

The *Guidelines* also informs the process of repowering projects, in which larger, taller, more efficient turbines replace smaller, outdated wind turbines. These repowering projects have the potential to improve the use of California's wind resources, while possibly altering the wind projects' impacts on avian and bat species. The suggestion in the 2005 *Integrated Energy Policy Report* (CEC 2005) that repowering will reduce or prevent bird deaths in the Altamont Pass Wind Resource Area has not been verified throughout the state. Further scientific research is needed to get a better understanding of the effects on local bird and bat populations when old turbines are replaced with much larger modern turbines. There is also a possibility that taller turbines could be more lethal to bats, but monitoring bat fatalities at smaller turbines has only recently received the same attention as monitoring for birds. The *Guidelines* recommends pre-permitting studies for repowering projects that address the issues that new turbines are typically taller than the ones they replace, reach a higher airspace, and have a much larger rotor-swept area. New turbines also have a longer operating time, operate at lower and higher wind speeds, and may have increased blade tip speed, all of which potentially affect different species (Barclay et al., 2007). The replacement of older wind turbines with newer, more efficient models may shift impacts from one species to another or result in different levels of impact to species already impacted by the existing smaller turbines.

Many states are considering creating or are in the process of formulating wind energy development guidelines, and California's guidelines will provide an excellent model for others to consider. Energy developers in California are striving to meet the state's RPS, so that a larger portion of California's energy supply will come from renewable energy sources such as wind. The CDFG and the Energy Commission encourage the use of the *Guidelines* for the biological assessment, mitigation, and monitoring of new wind energy development projects and wind turbine repowering projects in California. Submission of data to a central repository will allow monitoring of the *Guidelines'* usage and cumulative impact analysis of regional data from multiple projects. Future, consistent collection of data according to the *Guidelines* is expected to improve the forecasting of impacts. Staff will track and report on the *Guidelines* usage in future *Environmental Performance Reports*.

CHAPTER 7: Klamath Hydroelectric Project

Introduction and Policy Overview

California's 13,326 MW[55] hydropower system forms a critical element of the state's energy resource mix, comprising about 21 percent of in-state generating capacity and providing from 9 to 30 percent of the electricity consumed annually, depending on the water year and depth of the Sierra Nevada snowpack. Hydropower has traditionally been considered to be a low-impact energy resource because it does not emit toxic emissions and criteria pollutants associated with coal-fired and natural gas-fired generation. More recently, hydropower has been portrayed as a "clean energy resource" because it was believed to cause no greenhouse gas emissions; although emerging scientific studies are now documenting methane gas releases from reservoirs.

The Energy Commission has been one of few energy planning and policy agencies in the country to document the cumulative environmental impacts from hydropower operations. In the *2003 Environmental Performance Report*, staff summarized that:

> "Hydropower production contributes to significant, ongoing impacts to many California rivers and streams, endangered native wild salmon and trout populations, and the water quality needed to support sustainable riverine ecosystems. Thousands of miles of stream and river habitat can no longer support sustainable populations of native wild salmon and trout, amphibians and other aquatic species due to a suite of impacts from hydropower production, water supply and flood control projects, forestry practices, gravel mining, nonpoint source pollution, and other human activities. The majority of the state's hydropower projects were licensed by the Federal Energy Regulatory Commission (FERC) 30 or more years ago – prior to enactment of the major environmental statutes – and were subject to the environmental standards of that era. Most of the projects with older FERC licenses do not meet current state environmental standards."[56]

The scientific basis for this conclusion comes from several important systems-level environmental assessments of the impacts from power dams, water supply dams and other infrastructure affecting California's inland waters. Of particular note are findings from the Sierra Nevada Ecosystem Project report and from the National Marine Fisheries Service's regulatory work on California salmonids. A brief summary of these scientific findings include:

- The Sierra Nevada Ecosystem Project Report conducted by UC Davis found that aquatic and riparian systems are the most altered habitats in the Sierra Nevada, with dams cited as a major degradation factor: "Dams and diversions throughout most of the Sierra Nevada have

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[55] Earlier Energy Commission reports have used the figure of 14,116 MW for in-state hydro capacity. This revised figure represents refinements in the Energy Commission Quarterly Fuels Energy Report Database, and does not reflect decommissioning of any major hydropower projects.

[56] *California Hydropower System: Energy and Environment, Appendix D to the 2003 Environmental Performance Report*, Energy Commission Staff Report No. 100-03-018, October 2003.

profoundly altered stream-flow patterns (timing and amount of water) and water temperatures, with significant impacts to aquatic biodiversity."[57]

- Two-thirds of California's fresh water fish species have been impacted by hydroelectric development, and 67 percent of the state's native fish are extinct, endangered or in decline.[58]
- Dam construction in the Central Valley has eliminated 95 percent of the original 6,000 miles of salmonid habitat.[59]
- The "listing notices" in the Federal Register for California's four salmonid species now protected by the Endangered Species Act – winter and spring-run Chinook salmon, coho salmon and steelhead trout – identify the development and operation of hydroelectric projects as a causal factor in the species' declines.
- Population levels for the winter-run Chinook salmon declined from a range of 50,000 to 100,000 adult fish in the 1960s to runs of 300 to 500 adult fish in the 1990s, prompting an emergency listing notice under the Endangered Species Act by the National Marine Fisheries Service.[60]

A key factor in the environmental damage from hydropower results from the distribution of biodiversity in the Arid West. California has 67 native resident and anadromous (ocean-going) fish species, two-thirds of which are now endangered, imperiled, or extinct. By definition, these species are restricted to narrow bands of aquatic habitat within rivers and streams. The environmental stressors to freshwater habitats from dams for water supply, flood control and hydroelectric power, non-point source run-off from development and agricultural, and sedimentation from logging and gravel mining accumulate quickly in these aquatic habitats. The anticipated impacts from climate change will exacerbate the existing stresses to aquatic ecosystems in California.

Professor Jeffrey Mount and his colleagues at the University of California Davis Center for Watershed Sciences have secured a large grant from the Resources Legacy Foundation Fund to conduct an updated, interdisciplinary investigation on basin-scale impacts to fisheries and water quality from hydropower operations and climate change.

The Energy Commission found in the *2003 Integrated Energy Policy Report* that "The restoration of imperiled salmon and trout fisheries is one of California's environmental policy objectives" and that "decommissioning of high environmental impact hydroelectric facilities that supply little power is a possible method of restoring important aquatic habitat." Energy Commission staff has provided a series of energy assessments to the California State Water Resources Control Board and California Department of Fish and Game in support of their investigations on the feasibility and potential benefits of selective decommissioning of hydroelectric projects that directly impact

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[57] University of California, Davis. 1996. Status of the Sierra Nevada:Summary of the Sierra Nevada Ecosystem Project Report. Centers for Water and Wildland Resources, University of California.
[58] Mount, J.F. 1995. California Rivers and Streams: the conflict between fluvial process and land use. University of California Press.
[59] National Marine Fisheries Service, Endangered and Threatened Species, Status of Sacramento River winter-run Chinook Salmon, Final Rule, Federal Register, Vol. 59(2), page 440, January 4, 1994.
[60] *Ibid*.

endangered salmonid species but provide small amounts of electricity. These energy assessments have been done for the Battle Creek, Kilarc-Cow Creek, and Klamath River projects. The 2003 *Preliminary Assessment*[61] of the Klamath River Hydro Project is the most comprehensive of these decommissioning assessments and many findings from the 2003 report are still applicable to the current analyses of the Klamath Hydro Project.

The following section describes the extensive energy and economic analytic work that Energy Commission staff has sponsored and conducted to evaluate the potential decommissioning of the Klamath River Hydroelectric Project in Northern California and Southern Oregon.

Background of the Klamath Relicensing Proceeding and Energy Commission Involvement on Energy and Cost Issues

The Klamath River is one of the largest and most important rivers for salmon in California and Oregon (See Figure 14). Historically, it sustained the third largest runs of salmon on the West Coast. The river now provides habitat for several remnant runs of imperiled Chinook salmon, Coho salmon and steelhead trout. A 169 megawatt (MW) hydropower project consisting of four main dams and powerhouses, operated by PacifiCorp, has been a major contributor to the exclusion of salmon from over three hundred miles of habitat in the upper Klamath Basin. The hydro project contributes to significant, ongoing impacts to native salmon and trout populations and to water quality. Populations of Klamath Chinook salmon reached such critically low levels in 2006 that the Pacific Coast commercial salmon fishery in Northern California and southern Oregon was severely curtailed in order to protect the adult salmon returning to spawn in the Klamath River.

The current FERC relicensing proceeding will determine if and under what terms a new license should be granted to PacifiCorp to continue operating the Klamath Hydro Project (FERC Project No. 2082) under the Federal Power Act, and in accordance with the Endangered Species Act and Clean Water Act. The Klamath Hydroelectric Project, parts of which are almost 90 years old, does not meet current environmental regulatory standards. Substantial facility upgrades and mitigation measures such as fish ladders, water quality control devices, and new limitations on project operations could be required to provide for upstream and downstream salmon migration and to bring the project into conformance with current environmental standards. As an alternative to such potentially substantial mitigation measures, it may be more cost effective to decommission the hydro project, procure electricity from other sources, and restore the river's aquatic habitat.

Energy Commission staff, the U.S. Department of Interior's Office of Policy Analysis (Interior) and other state and federal energy and wildlife agencies in Oregon and California collaborated to analyze and compare the net economic costs for the relicensing and decommissioning scenarios.

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[61] *Preliminary Assessment of Energy Issues Associated with the Klamath Hydroelectric Project*, California Energy Commission Staff Report No. P700-03-007, Sacramento, California, May 2003.

The objective has been to design and conduct a rigorous, objective, and transparent analysis that can be used by government agencies and stakeholders in the FERC proceeding, settlement negotiations, and regulatory proceedings at the state Public Utilities Commissions with jurisdiction over PacifiCorp's service territory.

Dr. Richard McCann of M.Cubed is the report's primary author of this analysis. Under contract to the Energy Commission staff, he developed the conceptual framework and Klamath Project Alternatives Analysis Model (KPAAM) to analyze the costs for the two scenarios. The U.S. Bureau of Reclamation's (Bureau) Technical Services Center in Denver, Colorado developed the hydrologic model. Cost inputs for the mitigation measures were obtained from filings in the FERC relicensing proceeding from PacifiCorp, and state and federal agencies. Decommissioning cost estimates were developed by the California Coastal Conservancy and their engineering consultant. Replacement power cost estimates were obtained from independent, publicly available sources in the Pacific Northwest and California.

Results of the analysis are provided in the Energy Commission Consultant Report Economic *Modeling of Relicensing and Decommissioning Options for the Klamath Basin Hydroelectric Project*[62] *(Klamath Consultant Report)*. Energy Commission staff and M.Cubed prepared an Addendum[63] to the Klamath Consultant Report in response to a critique prepared by PacifiCorp and its economic consultant. Results and findings in the Addendum supersede those from the initial report and should be considered current.

Each of these reports and the KPAAM2 spreadsheet model has been submitted to the Federal Energy Regulatory Commission. In October 2007, Energy Commission staff sent letters from the Executive Director to the three public utilities commissions on the West Coast with rate jurisdiction over PacifiCorp. The letters transmitted the results of the Energy Commission staff's energy and economic analyses, and concluded that:

> "Based on the scientific, energy and economic evidence provided in this letter, the FERC proceeding administrative record, and in our reports, Energy Commission staff recommends that the California Public Utilities Commission authorize cost recovery only for the decommissioning scenario, which is the least-cost, environmentally superior project option for the Klamath Hydro Project."[64]

The reports, KPAAM2 spreadsheet model, and letters are available on our website, http://www.energy.ca.gov/klamath, along with other Klamath-related materials.

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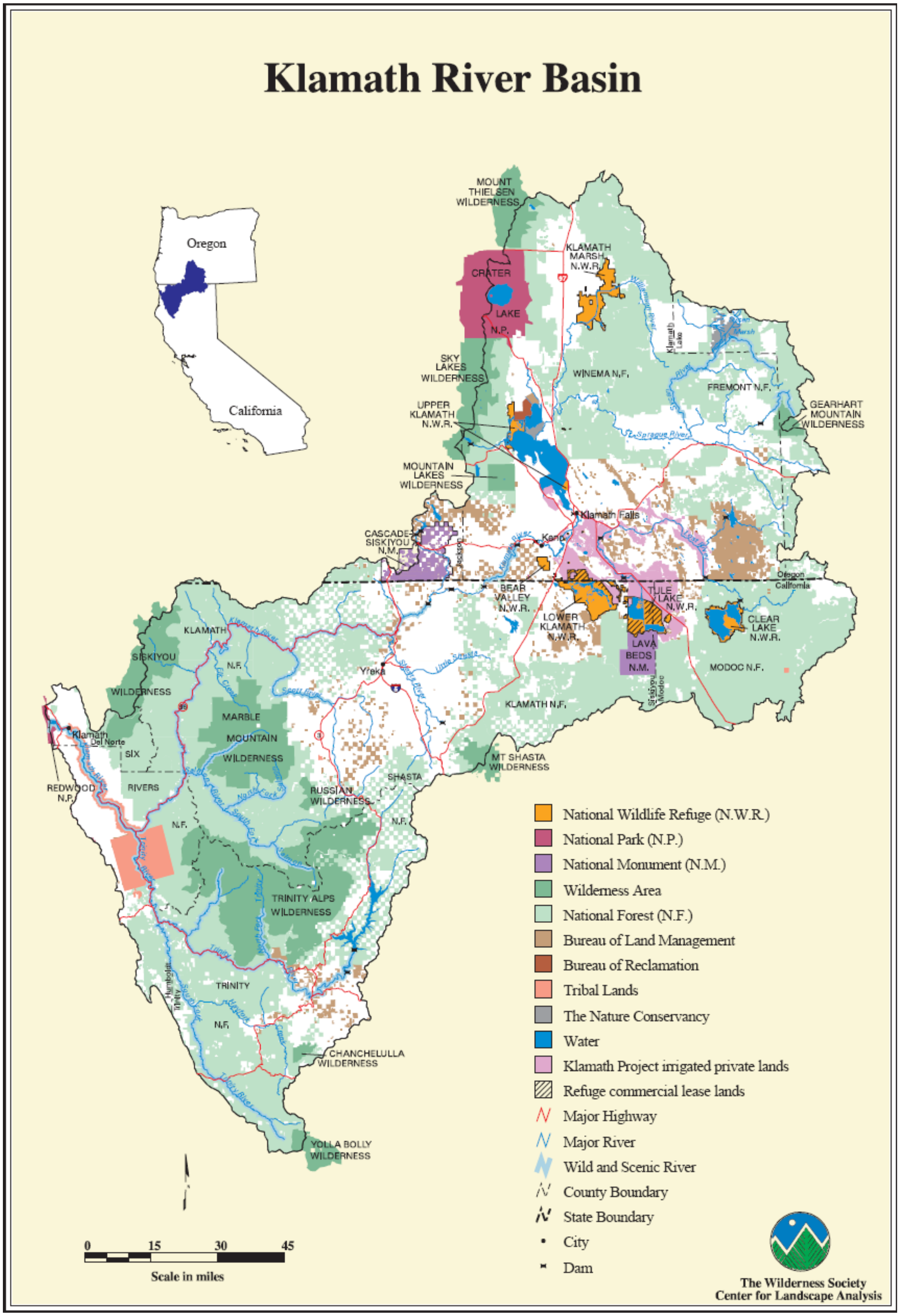
[62] *Economic Modeling of Relicensing and Decommissioning Options for the Klamath Basin Hydroelectric Project*, California Energy Commission Consultant Report, Publication No.700-2006-010, November 2006.

[63] *Addendum A – Response to PacifiCorp's Comments on the Klamath Project Alternatives Analysis Project*, California Energy Commission Consultant Report, Publication No. 700-2007-004-REV1, April 2007.

[64] Letters to the California Public Utilities Commission, Oregon Public Utility Commission, and Washington State Utilities and Transportation Commission, "PacifiCorp's Klamath Hydroelectric Project: Transmittal of Economic and Energy Information from the California Energy Commission to Assist Public Utilities Commissions in Identifying the Least-Cost Project Alternative for Ratepayers," October 29, 2007.

Figure 15: Location of Klamath River



Summary of Methods and Key Findings from the Klamath Consultant Report, Addendum and KPAAM2

1. Klamath Project Energy Summary

The Klamath Hydroelectric Project currently totals 169 MW nameplate capacity from four main power dams. FERC rates the project's dependable capacity at 42.7 MW. Current average annual generation is estimated to be about 716.8 gigawatt-hours (GWh). At the system level for PacifiCorp, the Klamath Hydro Project comprises two percent of total capacity, and contributes about one percent to total electricity sales.

Although generally portrayed as a peaking facility, the project operates more as a run-of-river facility due to a number of constraints. In its recent filings before the California Public Utilities Commission (CPUC), PacifiCorp acknowledges that it has little authority or operating discretion to dispatch the Klamath Project to meet electricity demands. The hydro project has no large storage reservoir capacity available for seasonal dispatch, and inflows from the Bureau's irrigation project at Upper Klamath Lake are governed by two recent biological opinions issued under the Endangered Species Act to protect threatened salmon and other fish species.

2. KPAAM Methods

KPAAM is a cost-effectiveness evaluation of two future project alternatives; relicensing with mitigation, and decommissioning with 30 years of replacement power. It is not a cost-benefit study, nor does it address the broader range of environmental and social impacts or benefits incurred by either option, such as changes in the fish runs, improvements in water quality, recreational opportunities, or regional economic impacts.

Cost inputs for three categories – mitigation costs, decommissioning costs and replacement power costs – were obtained from publicly available sources and integrated into the spreadsheet model with clearly stated assumptions. Conservative assumptions are used to identify the probable mitigation measures and a 30 percent uncertainty factor is used to account for the broad ranges of complexity and uncertainty in mitigation costs and final regulatory requirements. Standard economic analytic methods are used throughout. Results are appropriately discounted and presented as consistent net present values. The actual spreadsheet model is based on a similar cost of generation model that has been developed by the Energy Commission for use at the CPUC. An associated hydrologic model of Klamath River flows was also developed to model current and future project operations from a variety of possible future constraints. Methods, assumptions and full descriptions of cost inputs are provided in the *Klamath Consultant Report*.

After PacifiCorp provided its critique of KPAAM and the *Klamath Consultant Report* to FERC, Energy Commission staff and M.Cubed revised the model and modified several cost inputs, model formulas and assumptions. The second model run is entitled KPAAM2. Revisions and findings are presented in the *Addendum*.

3. KPAAM2 Results

Results of KPAAM2 are generally consistent with the results of the initial model run, which found that for a broad range of assumptions and replacement power forecasts, it would generally be more cost effective to decommission rather than relicense the Klamath Hydro Project.

Relicensing condition with Agency-Mandated and Recommended Mitigation

Costs for over 160 mandatory and recommended mitigation measures were compiled from the March 29, 2006 FERC filings from PacifiCorp, and state and federal agencies. Proxies were used for the water quality measures necessary to meet Section 401 of the Clean Water Act, since they have not yet been prepared by the California and Oregon water quality agencies. Most of the flow-related measures were captured in the hydrologic modeling results.

Relicensing Condition mitigation measures include:

- **Fish Passage Conditions** for full volitional upstream and downstream passage past four power dams (fish ladders), spillway and tailrace improvements, and hatchery operations.
- **Non-fish Passage Conditions** such as gravel augmentation, riparian restoration, terrestrial resource protection, recreational enhancements, and cultural resource protection.
- **Water Quality Conditions** to comply with water quality standards per section 401(e) of the Clean Water Act, including installation of oxygen diffusers at Iron Gate, and temperature control devices at Iron Gate and Copco 2. Since water quality measures to meet Section 401 of the Clean Water Act have not yet been prepared by the California and Oregon water quality agencies these estimates are proxies.

As shown in Table 20, total net present value (NPV) of the extensive mitigation measures likely to be required to reduce environmental damage from the 169 MW Klamath Hydro Project range from $223 to $415 million, with a midline estimate of $320 million. The operational mitigation measures would reduce power production by 23 percent to 563 GWh and further constrain peaking dispatch flexibility.

Table 20: Net Present Values of Klamath Relicensing Mitigation Costs

Net Present Values of Klamath Relicensing Mitigation Costs (Millions of 2006 Dollars)			
	Low	*Midline*	*High*
Fish Passage	$164	$235	$305
Nonfish Passage	$14	$20	$26
Water Quality	$45	$65	$84
Total	$223	$320	$415

Decommissioning Condition

The Decommissioning Condition developed for KPAAM assumes removing the Boyle, Copco I and II, and Iron Gate dams and powerhouses.[65] Decommissioning would occur between 2013 and 2015. Existing license conditions for operations and generation are assumed to continue until decommissioning, although interim measures may be developed. The two main costs for the Decommissioning Condition are dam removal and replacement power.

Dam Removal: The modeling team used a dam removal cost estimate developed for the California Coastal Conservancy that was most recently updated in September 2006. The nominal dollar estimate is $89.6 million. A more detailed decommissioning study is underway by the Conservancy and its consultant Gathard Engineering and Construction. These revised cost estimates can be added to future KPAAM scenarios when available.

Replacement Power: Estimates for replacement power costs were derived for a 30-year period from 2008 to 2038. The modeling team identified six publicly available wholesale price forecasts that are intended to cover a reasonable range of assumptions and scenarios used by energy planning agencies and utilities. Estimates are presented as 30-year levelized costs in 2005 dollars to allow for "apples to apples" comparisons.

Energy Forecast	$ / MWh
PacifiCorp, July 2005, Avoided Cost Filing - Oregon PUC	$66.10
U.S. Dept. of Interior, March 2006, FERC Filing	$37.00
Northwest Power Planning Council 5th Power Plan	$44.59
DOI + PacifiCorp Avoided Cost + EIA Gas Price	$45.25
Oregon Dept. of Energy: Biomass + DSM	$58.18
CPUC Market Price Referent: Combined Cycle Gas	$79.44

[65] Keno Dam, a non-generating facility, is assumed to remain in place in this analysis.

As shown in Table 21, total NPV decommissioning and replacement power costs for 30 years would range from $96 to $224 million. Decommissioning costs would range from $38 to $71 million, while 30-year NPV replacement power costs based upon six separate forecasts would range from $58 to $153 million.

Table 21: Total NPV Costs of Decommissioning

Total NPV Costs of Decommissioning: Dam Removal plus Replacement Power (Millions of 2006 Dollars)				
	Total Decommissioning Costs	*Low*	*Midline*	*High*
		$38	*$55*	*$71*
	30-Year Total Replacement Power Costs	**Replacement Power plus Dam Removal Costs**		
Replacement Power Cost Forecast		Low	Midline	High
U.S. Department of Interior (DOI)	$58	$96	$113	$129
U.S. DOI-PacifiCorp+Energy Information Agency	$83	$121	$138	$154
Northwest Power Planning Council 5th Power Plan	$106	$144	$161	$177
Oregon Dept of Energy	$111	$149	$166	$182
PacifiCorp 2005 Filing with Oregon PUC	$151	$189	$206	$222
California Public Utilities Commission MPR	$153	$191	$208	$224
Relicensing Mitigation Costs		*$223*	*$320*	*$415*

Table 22 shows the net benefits of decommissioning compared to relicensing, or the total cost differences between the two project options. Another way to interpret the table is to imagine "A - B = C," where A is the cost of relicensing with mitigation shown in Table 20, B is the cost of decommissioning with 30 years of replacement power shown in Table 21, and C is the net difference between the two project options. Table 22 shows the C values.

The final results from KPAAM2 shown in Table 22 indicate that decommissioning with replacement power is less costly than relicensing with mitigation across a wide range of assumptions and replacement power cost estimates. All values are positive, indicating net benefits to ratepayers across all scenarios. Economic benefits to PacifiCorp ratepayers from the decommissioning option would range from $32 million to $286 million. For the midline case using PacifiCorp's own replacement power forecast, it would be $114 million less costly to decommission the facilities, restore the fisheries and procure replacement power for thirty years rather than relicense the Klamath Hydro Project and install the extensive array of mitigation measures likely to be required by FERC and the other environmental regulatory agencies.

Table 22: Net Differences Between the Decommissioning and Mitigated Relicensing Project Options

Net Benefits of Decommissioning Compared to Relicensing			
	Net Present Value (millions of 2006 Dollars)		
Power Price Forecasts	**Low**	**Midline**	**High**
U.S. Department of Interior (DOI)	$127	$207	$286
U.S. DOI-PacifiCorp+Energy Information Agency	$102	$182	$261
Northwest Power Planning Council 5th Power Plan	$79	$159	$238
Oregon Department of Energy – Biomass + DSM	$74	$154	$233
PacifiCorp 2005 Filing with Oregon PUC*	$34	$114	$193
California Public Utilities Commission MPR*	$32	$112	$191

* Costs are for new combined-cycle power plant.

Energy Commission Staff Perspective on Klamath

At this point in the Klamath Relicensing Proceeding, state and federal fisheries, wildlife and water quality agencies have developed an extensive scientific record documenting the environmental damage to regionally significant populations of imperiled salmonids from historic operation of the Klamath Hydro Project. These scientific findings were confirmed by the trial judge in the administrative hearings conducted pursuant to the Energy Policy Act in August 2006.

Relicensing with the associated mitigation costs creates the highest risk for PacifiCorp ratepayers. The engineering and scientific issues associated with trying to maintain power production and mitigate impacts are complex and expensive. PacifiCorp shareholders and ratepayers risk not recouping all of the potential costs associated with long-term mitigation and power production, especially if a lower cost, biologically superior project option has been identified in the NEPA record.

The Energy Commission staff's investigations into the energy values associated with the project document that this 169 MW hydroelectric facility is a nominal energy resource that contributes only one percent to PacifiCorp's total electricity supply. Project operations and dispatch flexibility are highly constrained by Bureau of Reclamation operations, and would be further constrained by the likely mitigation measures imposed by FERC and other agencies. Our 2003 study showed that loss of the facility's generation would not significantly affect PacifiCorp's ability to serve customer load, and that replacement power for the project's intermittent, non-firm power is available from thermal and renewable resources in the Pacific Northwest. Based on this information, investing hundreds of millions in ratepayer money, to sustain a nominal and environmentally damaging power plant, especially when lower cost, environmentally superior project alternatives are available, does not appear to be a prudent economic decision for PacifiCorp's rate payers.

The opportunity costs for alternative investments of this ratepayer money are significant. For example, for $320 million a 170 MW wind farm could be constructed that produces intermittent, emissions-free electricity. For $350 to $400 million, developers in California are constructing state-of-the-art 500 MW natural gas-fired combined cycle power plants that meet our state's stringent air quality standards and produce firm power with some dispatch flexibility. Based on data from the Oregon Energy Trust, which administers Oregon's energy efficiency programs, investing $320 million in energy efficiency measures could secure about 2,000 GWh annually in energy savings (228 average MW) over a 14-year period, nearly three times the Klamath Hydro Project's current annual energy production of 716 GWh.

PacifiCorp has expressed concern about the potential incremental increases in greenhouse gas emissions from thermal replacement power sources; however, it is important to recognize that 68 percent of PacifiCorp's generation is from coal-fired power plants (6,585 MW) and another four percent from gas-fired facilities. According to the firm's Preferred Portfolio in its *2007 Integrated Resource Plan*, PacifiCorp proposes to build two new coal facilities and increase ownership in a third by 2015, and construct three new combined cycle gas-fired power plants by 2016 for a total of 2,674 MW in new fossil-fueled capacity. Climate change emissions from these new thermal resources create a far larger carbon footprint than the incremental avoided emissions from the 169 MW Klamath Hydro Project.

FERC's relicensing proceeding for the Klamath Hydro Project provides a unique opportunity to help restore the historically significant runs of salmon and steelhead to the Klamath River Basin. Low power-high environmental impact power plants like those on the Klamath River require significant and unique energy benefits to justify their continued operations: no such unique benefits have been identified. Current energy policies in California and throughout the West are reducing electricity demand and creating fleets of modern, cost-effective power plants that minimize damage to the environment and maintain electric system reliability, greatly reducing the need for outmoded, environmentally damaging facilities such as the Klamath Hydro Project.

The energy and economic analyses conducted by Energy Commission staff and its consultant, coupled with the extensive scientific information contained in the administrative record for the relicensing proceed, demonstrate that decommissioning with replacement power is the least-cost and biologically superior project option.

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APPENDIX A:
Cooling Water Tables

Data for CEC Jurisdictional Plants from 1996-2007
(Organized by AFC Filing Date)

No.	County	Name of Power Plant	Docket No.	Generator Type	Water Supply	Wastewater Disposal Systems	Average capacity MW	Average annual water use (acre-ft)	Status
1	Sacramento	Procter & Gamble (SMUD)	---	Cogeneration	Groundwater	Sanitary Sewer	117	1806	Operational
2	Lake	Bottle Rock Geothermal - U.S.	79-AFC-4	Steam turbine	Groundwater	ZLD	20	---	Under Construction
3	Contra Costa	Crockett Cogeneration - Delta Power	92-AFC-01	Combined Cycle	Freshwater	Sanitary Sewer	240	---	---
4	San Bernardino	High Desert	97-AFC-1	Combined Cycle	Groundwater	ZLD	830	4000	Operational
5	Sutter	Sutter Power Project	97-AFC-2	Combined Cycle	Groundwater	ZLD	540	225	Operational
6	Contra Costa	Los Medanos Energy Center	98-AFC-1	Cogeneration	Recycled or Degraded	Sanitary Sewer	555	4000	Operational
7	Kern	La Paloma	98-AFC-2	Combined Cycle	Freshwater	Injection Wells	1124	6000	Operational
8	Contra Costa	Delta Energy Center	98-AFC-3	Combined Cycle	Recycled or Degraded	Sanitary Sewer	887	5900	Operational
9	Kern	Sunrise	98-AFC-4	Simple Cycle	Groundwater	Injection Wells	320	18	Operational
10	Kern	Elk Hills	99-AFC-1	Combined Cycle	Groundwater	Offsite Wells	500	3200	Operational
11	Santa Clara	Metcalf Energy Center	99-AFC-3	Combined Cycle	Recycled or Degraded	Sanitary Sewer	600	3600	Operational
12	Monterey	Moss Landing	99-AFC-4	Combined Cycle	Ocean, Estuary, or River	Ocean, Estuary, or River	1060	403200	Operational

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No.	County	Name of Power Plant	Docket No.	Generator Type	Water Supply	Wastewater Disposal Systems	Average capacity MW	Average annual water use (acre-ft)	Status
13	San Diego	Otay Mesa - Calpine	99-AFC-5	Combined Cycle	Freshwater	Sanitary Sewer	510	385	Under Construction
14	Kern	Pastoria Phase 1 Units 1, 2, & 3 - Calpine	99-AFC-7	Combined Cycle	Freshwater	ZLD	750	3750	Operational
15	Riverside	Blythe Energy Project	99-AFC-8	Combined Cycle	Groundwater	Evaporation Ponds	520	3000	Operational
16	Contra Costa	Gateway - PG&E (formerly Contra Costa - Migrant)	00-AFC-1	Combined Cycle	Recycled	Ocean, Estuary, or River	530	---	---
17	San Bernardino	Mountain View Units 3&4 - Edison Mission Energy	00-AFC-2	Combined Cycle	Recycled or Degraded	Sanitary Sewer	528	7500	Operational
18	San Luis Obispo	Morro Bay - L.S. Power	00-AFC-12	Combined Cycle	Ocean, Estuary, or River	Ocean, Estuary, or River	1200	532000	On Hold
19	Orange	Huntington Beach Units 3 and 4 – AES	00-AFC-13	Steam turbine	Ocean, Estuary, or River	Ocean, Estuary, or River	225	283800	Operational
20	Los Angeles	El Segundo Repower - Dynegy/NRG	00-AFC-14	Combined Cycle	Ocean, Estuary, or River	Evaporation Ponds	630	215,209	On Hold
21	San Diego	Wildflower Larkspur -Intergen	01-EP-01	Simple Cycle	Freshwater	Sanitary Sewer	90	---	Operational

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No.	County	Name of Power Plant	Docket No.	Generator Type	Water Supply	Wastewater Disposal Systems	Average capacity MW	Average annual water use (acre-ft)	Status
22	Riverside	Wildflower Indigo - Intergen	01-EP-02	Simple Cycle	Freshwater	Surface Water	135	---	Operational
23	San Bernardino	Century - Alliance	01-EP-04	Simple Cycle	Groundwater	Trucked Offsite	42	---	Operational
24	San Bernardino	Drews	01-EP-5	Simple Cycle	Freshwater	Trucked Offsite	40	32	Operational
25	Alameda	East Altamont - Calpine	01-AFC-4	Combined Cycle	Freshwater	ZLD	1100	4600	On Hold
26	Monterey	King City - Calpine	01-EP-06	Simple Cycle	Groundwater	Sanitary Sewer	50	---	Operational
27	Kings	GWF Hanford Peaker	01-EP-07	Combined Cycle	Groundwater	Sanitary Sewer	95	800	Operational
28	Santa Clara	Gilroy Peaker Units 1, 2, & 3	01-EP--8	Simple Cycle	Groundwater	Sanitary Sewer	135	745	Operational
29	---	---	01-EP11	---	---	---	---	---	---
30	Solano	Valero Cogeneration Units 1 and 2	01-AFC-5	Cogeneration	Freshwater	Ocean, Estuary, or River	51	314	Unit 1 : Operational Unit 2: On Hold
31	Los Angles	Magnolia-Social Power Authority	01-AFC6	Combined Cycle	Recycled or Degraded	ZLD	328	5100	Operational

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No.	County	Name of Power Plant	Docket No.	Generator Type	Water Supply	Wastewater Disposal Systems	Average capacity MW	Average annual water use (acre-ft)	Status
32	Stanislaus	Wooldland ll	01-SPPE-1	Combined Cycle	Freshwater	Sanitary Sewer	80	470	Operational
33	San Diego	Calpeak Escondido	01-EP-10	Simple Cycle	Freshwater	Trucked Offsite	50	3	Operational
34	Alameda	Russell City - Calpine	01-AFC-7	Combined Cycle	Recycled or Degraded	Sanitary Sewer	600	3731	On Hold
35	San Diego	Calpeak Border	01-EP14	Simple Cycle	Freshwater	Trucked Offsite	50	16	Operational
36	Santa Clara	Los Esteros Critical Energy Facility	01-AFC-12	Simple Cycle	Recycled or Degraded	Sanitary Sewer	135	560	Operational
37	San Joaquin	Tracy Peaker	01-AFC-16	Simple Cycle	Freshwater	Trucked Offsite	169	30	Operational
38	Riverside	Inland Empire - GE & Capline	01-AFC-17	Combined Cycle	Recycled or Degraded	Sanitary Sewer	800	4200	under construction
39	Kings	GWF Henrietta	01-AFC-18	Simple Cycle	Freshwater	Trucked Offsite	96	160	Operational
40	Sacramento	SMUD Consumes Combnined Cycle Phase 1	01-AFC-19	Combined Cycle	Freshwater	ZLD	500	8000	Operational
41	Alameda	Tesla - FPL	01-AFC-21	Combined Cycle	Freshwater	ZLD	1120	5100	On Hold
42	Fresno	San Joaquin Valley Energy Center - Calpine	01-AFC-22	Combined Cycle	Groundwater	ZLD	1087	5340	On Hold

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No.	County	Name of Power Plant	Docket No.	Generator Type	Water Supply	Wastewater Disposal Systems	Average capacity MW	Average annual water use (acre-ft)	Status
43	San Diego	Palomar Escondido - Sempra	01-AFC-24	Combined Cycle	Recycled or Degraded	Sanitary Sewer	524	3600	Operational
44	Los Angles	Malberg - City of Vernon	01-AFC-25	Combined Cycle	Recycled or Degraded	Sanitary Sewer	134	1400	Operational
45	Riverside	Blythe II - Blythe Energy	02-AFC-1	Combined Cycle	Groundwater	Evaporation Pond	520	3300	On Hold
46	Imperial	Salton Sea Geothermal	02-AFC-2	Steam Turbine	Groundwater	Injection Well	215	293	On Hold
47	Santa Clara	Donald Von Raesfeld	02-AFC-3	Combined Cycle	Recycled or Degraded	Sanitary Sewer	147	1182	Operational
48	Stanislaus	Walnut Energy Center-Turlock Irrigation District	02-AFC-4	Combined Cycle	Recycled or Degraded	ZLD	250	1800	Operational
49	Placer	Roseville - Roseville	03-AFC-1	Combined Cycle	Recycled or Degraded	ZLD	160	1247	Under Construction
50	San Joaquin	Ripon - MID	03-SPPE-1	Simple Cycle	Freshwater	Sanitary Sewer	95	394	Operational
51	Fresno	King River Conseravation District Peaker	03-SPPE-2	Simple Cycle	Groundwater	ZLD	97	75	Operational
52	Santa Clara	Los Esteros 2 - Calpine	03-AFC-2	Combined Cycle	Recycled or Degraded	Sanitary Sewer	140	560	On Hold

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(Organized by AFC Filing Date)

No.	County	Name of Power Plant	Docket No.	Generator Type	Water Supply	Wastewater Disposal Systems	Average capacity MW	Average annual water use (acre-ft)	Status
1	San Francisco	San Francisco Reliability Project - City of San Francisco	04-AFC-1	Simple Cycle	Recycled or Degraded	Sanitary Sewer	135	132	On Hold
2	Riverside	Riverside Energy Resource Center	04-SPPE-1	Simple Cycle	Recycled or Degraded	ZLD	48	247	Operational
3	Kern	Pastoria Phase 2 Expansion Project - Calpine	05-AFC-1	Simple Cycle	Freshwater	ZLD	160	55	On Hold
4	Los Angeles	Walnut Creek Energy Park - Edison Mission Energy	05-AFC-2	Simple Cycle	Recycled or Degraded	Sanitary Sewer	500	885	Review
5		Sun Valley Energy Project - Edison Mission	05-AFC-3	Simple Cycle	Recycled	Sanitary Sewer	500	851	Review
6	Imperial	Niland Peaker-Imperial irrigation District	06-SPPE-1	Simple Cycle	Freshwater	ZLD	93	20.75	Under Construction
7	Imperial	EL Centro Unit 3 Repower - Imperial Irrigation District	06-SPPE-2	Combustion turbine	Freshwater	Injection Wells	85	1029	Under Construction
8	San Bernarndino	Highgrove - AES	06-AFC-2	Simple Cycle	Groundwater	Sanitary Sewer	300	366	Review
9	San Diego	South Bay Replacement Projects - L.S. Power	06-AFC-3	Combined Cycle	Freshwater	Sanitary Sewer	620	129	On Hold
10	Los Angeles	Vernon Power Plant - City of Vernon	06-AFC-4	Combined Cycle	Recycled or Degraded	Sanitary Sewer	914	6266	Review

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Organized by AFC Filing Date)

No.	County	Name of Power Plant	Docket No.	Generator Type	Water Supply	Wastewater Disposal Systems	Average capacity MW	Average annual water use (acre-ft)	Status
11	Fresno	EIF Firebaugh Panoche - Energy Investors Fund	06-AFC-5	Simple Cycle	Groundwater	Injection Wells	400	805	Review
12	Alameda	Eastshore - Tierra Energy	06-AFC-6	Gas fired reciprocating engine	Freshwater	Sanitary Sewer	116	1.6	Review
13	Humboldt	Humboldt Bay Repowering Project - PG&E	06-AFC-7	Dual-fuel Reciprocating engine	Groundwater	Sanitary Sewer	163	2.7	Review
14	Fresno	EIF Fresno/Bullard - Energy Investors Fund	06-AFC-8	Simple Cycle	Freshwater	Sanitary Sewer	200	671	Review
15	Colusa	Colusa - E&L Westcoast	06-AFC-9	Combined Cycle	Freshwater	ZLD	660	126	Review
16	Alameda	Russell City Energy Center - Russell City Energy Company	01-AFC-7C	Combined Cycle	Recycled or Degraded	ZLD	600	2490	Review
17	Fresno	Starwood Firebaugh Panoche - Starwood Power-Midway	06-AFC-10	Simple Cycle	Groundwater	Evaporation Pond	120	13.6	Review
18	Contra Costa	Gateway (Contra Costa Unit 8) - PG&E	00-AFC-1C	Combined Cycle	Freshwater	Sanitary Sewer	530	120	Review

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No.	County	Name of Power Plant	Docket No.	Generator Type	Water Supply	Wastewater Disposal Systems	Average capacity MW	Average annual water use (acre-ft)	Status
19	San Bernardino	Victorville 2 Hybrid Power Project	07-AFC-1	Combined Cycle and Solar Thermal	Recycled or Degraded	ZLD	563	3150	Review
20	San Diego	Larkspur Energy Facility - Larkspur 3	01-EP-1C	Simple Cycle and gas fired reciprocating engine	Freshwater	Sanitary Sewer	47	---	Suspended
21	San Bernardino	San Gabriel Generating Station - Reliant	07-AFC-2	Combined Cycle	Recycled and Groundwater	Sanitary Sewer	656	220	Review
22	Los Angeles	El Segundo Repower - Dynegy/NRG	00-AFC-14C	Combined Cycle	Recycled or Degraded	ZLD	560	34	On Hold
23	Contra Costa	Chevron Richmond Power Plant Replacement Project	07-SPPE-1	Cogenertion	Recycled or Degraded	Ocean, Estuary, or River	60	1486	Review
24	Riverside	Sentinal - CPV Sentinel	07-AFC-03	Simple Cycle	Groundwater	ZLD	800	550	Review
25	San Diego	Orange Grove - Orange Grove Energy	07-SPPE-2	Simple Cycle	Freshwater	Trucked Offsite	100	117	Review

NOTES:

na = not applicable
AWT = advanced treatment facility
ZLD = zero liquid discharge
RWF = Title 22 recycled water facility (tertiary water treatment)
EP = Emergency Peaker
SPPE = Small Power Plant Exception

APPENDIX B:
Coastal Power Plants with Once-Through Cooling

2001-2006 Plant-Level Capacity Factors – Calculated from Energy Commission QFER Database

	Plant-Leval Annual Capacity Factor						Net MWh						MW					
Plant Name	2001	2002	2003	2004	2005	2006	2001	2002	2003	2004	2005	2006	2001	2002	2003	2004	2005	2006
Alamitos	47.0%	22.9%	19.2%	16.0%	7.1%	9.7%	8,580,856	4,221,042	3,537,279	2,954,374	1,311,112	1,676,725	2,083	2,103	2,103	2,103	2,103	1,970
Contra Costa Power Plant	55.8%	32.8%	9.1%	12.8%	5.6%	2.3%	3,325,748	1,951,799	540,947	764,669	331,037	138,808	680	680	680	680	680	680
Diablo Canyon	94.1%	84.5%	89.6%	78.9%	92.0%	95.7%	18,151,997	16,305,208	17,285,039	15,210,201	17,755,302	18,464,983	2,202	2,202	2,202	2,202	2,202	2,202
El Segundo Power	32.7%	28.0%	14.3%	5.5%	7.4%	10.5%	2,918,237	2,444,549	1,275,123	487,057	664,261	617,257	1,020	996	1,020	1,020	1,020	670
Encina	46.5%	28.3%	29.4%	37.4%	22.1%	14.8%	3,865,374	2,353,084	2,443,082	3,109,339	1,866,531	1,254,647	948	948	948	948	965	965
Harbor	25.5%	28.5%	14.0%	8.6%	7.3%	5.2%	594,510	664,712	567,607	347,895	296,298	210,537	266	266	462	462	462	462
Haynes	24.1%	16.9%	18.1%	14.5%	25.9%	24.7%	3,315,253	2,328,262	2,484,718	2,046,335	3,648,483	3,481,810	1,570	1,570	1,570	1,606	1,606	1,606
Humboldt Bay	56.1%	31.3%	18.8%	31.0%	36.4%	36.8%	673,401	375,715	225,065	372,161	437,432	441,313	137	137	137	137	137	137
Huntington Beach	14.9%	14.6%	19.3%	24.9%	17.5%	12.9%	1,318,185	1,298,554	1,715,902	2,206,930	1,554,596	1,140,738	1,013	1,013	1,013	1,013	1,013	1,013
Mandalay Generating Station	42.2%	20.7%	12.6%	13.7%	7.1%	6.3%	2,068,332	1,013,877	618,777	670,075	350,532	314,663	560	560	560	560	560	573
Morro Bay Power Plant	51.7%	19.1%	3.8%	4.2%	4.0%	4.1%	4,127,050	1,528,516	299,705	332,148	319,260	324,525	912	912	912	912	912	912
Moss Landing Power Plant	68.5%	30.0%	30.6%	28.7%	24.6%	29.4%	8,447,049	6,522,635	6,654,235	6,244,311	5,350,741	6,405,358	1,407	2,484	2,484	2,484	2,484	2,484
Ormond Beach Generating Station	45.7%	17.8%	13.8%	17.1%	4.0%	3.3%	6,007,989	2,336,740	1,819,221	2,248,643	524,716	472,936	1,500	1,500	1,500	1,500	1,500	1,613
Pittsburg Power Plant	57.9%	21.9%	11.1%	10.2%	5.4%	3.7%	10,254,961	3,884,118	1,959,045	1,802,824	652,862	447,251	2,022	2,022	2,022	2,022	1,370	1,370
Potrero Power	36.3%	18.0%	27.2%	28.1%	13.5%	17.4%	1,155,807	572,284	864,864	892,234	430,618	554,758	363	363	363	363	363	363
Redondo Beach LLC	53.7%	18.0%	9.1%	11.0%	3.7%	5.0%	6,165,709	2,066,461	1,042,723	1,262,542	424,212	582,978	1,310	1,310	1,310	1,310	1,310	1,343
San Onofre	76.7%	91.4%	92.7%	76.1%	93.2%	68.7%	15,141,822	18,048,121	18,308,751	15,031,159	18,400,010	13,570,840	2,254	2,254	2,254	2,254	2,254	2,254
Scattergood	24.8%	16.5%	31.7%	24.8%	13.6%	21.3%	1,743,859	1,160,981	2,227,165	1,741,384	956,572	1,498,069	803	803	803	803	803	803
South Bay Power Plant	31.8%	20.0%	21.4%	30.8%	24.7%	15.5%	1,975,917	1,243,774	1,330,238	1,914,844	1,534,662	959,575	709	709	709	709	709	709
							99,832,056					52,557,771						

Notes:

Includes steam turbine and combined-cycle units. Excludes simple-cycle combustion turbine units

Total active generating plants using once-through cooling = 19

APPENIX B: Coastal Power Plant Units with Once-Through Cooling

2001-2006 Unit-Level Capacity Factors Through 2006 Calculated Based on CEC QFER Generation Database

		Unit-Level Capacity Factors						Net MWh						MW					
Plant Name	Unit	2001	2002	2003	2004	2005	2006	2001	2002	2003	2004	2005	2006	2001	2002	2003	2004	2005	2006
Alamitos	1	10.0%	9.5%	8.1%	6.5%	2.7%	3.3%	152,582	145,384	124,706	99,975	41,526	50,032	175	175	175	175	175	175
	2	20.7%	11.1%	8.5%	6.9%	2.1%	2.7%	316,701	169,842	130,173	105,647	32,665	41,327	175	175	175	175	175	175
	3	44.5%	35.0%	36.7%	23.7%	9.1%	17.1%	1,246,193	1,000,506	1,046,905	675,929	260,716	487,623	320	326	326	326	326	326
	4	47.6%	23.6%	20.8%	19.1%	5.5%	7.9%	1,334,192	669,664	591,286	543,098	155,027	225,536	320	324	324	324	324	324
	5	66.9%	33.7%	20.2%	25.2%	9.3%	9.3%	2,812,989	1,431,646	858,710	1,070,064	393,998	393,097	480	485	485	485	485	485
	6	63.8%	18.8%	18.4%	10.8%	10.1%	11.3%	2,681,308	798,059	782,660	459,661	427,180	479,110	480	485	485	485	485	485
Contra Costa Power Plant	6	62.0%	28.5%	1.9%	4.1%	1.1%	0.8%	1,846,500	847,953	56,233	121,481	34,088	24,928	340	340	340	340	340	340
	7	49.7%	37.1%	16.3%	21.6%	10.0%	3.8%	1,479,248	1,103,846	484,714	643,188	296,949	113,880	340	340	340	340	340	340
Diablo Canyon	1	98.4%	72.7%	99.2%	74.6%	86.0%	102.9%	9,503,622	7,020,202	9,585,431	7,208,257	8,313,575	9,944,983	1103	1103	1103	1103	1103	1103
	2	89.8%	96.4%	80.0%	83.1%	98.1%	88.5%	8,648,375	9,285,006	7,699,608	8,001,944	9,441,727	8,520,000	1099	1099	1099	1099	1099	1099
El Segundo Power	1	19.4%	3.3%					297,022	47,571					175	163				
	2	17.0%	1.6%					259,904	22,837					175	163				
	3	24.4%	35.3%	23.7%	8.8%	12.5%	11.6%	716,640	1,035,943	696,180	258,510	366,353	339,515	335	335	335	335	335	335
	4	56.0%	45.6%	19.7%	7.8%	10.2%	9.5%	1,644,671	1,338,198	578,943	228,547	297,908	277,742	335	335	335	335	335	335
Encina	1	41.1%	16.8%	13.8%	20.4%	15.6%	4.6%	342,217	139,554	114,506	169,757	146,205	42,911	95	95	95	95	107	107
	2	40.2%	19.4%	15.5%	23.7%	17.3%	9.6%	366,631	176,549	141,348	216,139	157,440	87,071	104	104	104	104	104	104
	3	46.5%	18.8%	21.1%	34.2%	18.7%	11.6%	447,600	181,019	203,478	329,607	179,890	111,523	110	110	110	110	110	110
	4	56.5%	33.1%	33.7%	43.9%	30.7%	17.9%	1,484,827	869,626	886,183	1,153,198	806,465	470,393	300	300	300	300	300	300
	5	42.6%	34.6%	38.5%	43.5%	19.9%	18.7%	1,214,083	985,062	1,095,215	1,237,406	575,978	541,681	325	325	325	325	330	330
Harbor	CC	28.4%	31.7%	24.9%	15.1%	13.5%	9.1%	594,510	664,712	496,052	300,721	267,526	180,326	239	239	227	227	227	227
Haynes	All	23.6%	16.5%	17.7%	14.5%	25.9%	24.7%	3,315,253	2,328,262	2,484,718	2,046,335	3,648,483	3,481,810	1606	1606	1606	1606	1606	1606
Humboldt Bay	1	62.1%	39.7%	26.8%	38.7%	46.6%	46.2%	288,284	184,332	124,366	179,741	216,451	214,673	53	53	53	53	53	53
	2	77.3%	38.8%	18.7%	38.4%	45.0%	45.6%	365,819	183,478	88,236	181,674	212,662	215,772	54	54	54	54	54	54
Huntington Beach	1	36.2%	31.5%	36.5%	38.6%	26.0%	20.4%	681,118	593,836	687,507	726,128	489,439	384,361	215	215	215	215	215	215
	2	32.4%	37.4%	36.8%	40.8%	22.1%	16.7%	610,778	704,718	692,315	767,623	415,798	314,227	215	215	215	215	215	215
	3			8.2%	18.7%	19.3%	11.6%			160,724	368,439	379,713	229,597	225	225	225	225	225	225
	4			8.9%	17.5%	13.7%	10.8%			175,356	344,740	269,646	212,553	225	225	225	225	225	225
Mandalay Generating Station	1	53.7%	25.2%	14.2%	15.5%	7.3%	7.8%	1,011,606	474,274	268,375	291,888	137,567	148,318	215	215	215	215	215	218
	2	54.2%	28.2%	18.1%	20.1%	11.2%	8.6%	1,019,962	531,217	341,282	378,187	211,460	163,999	215	215	215	215	215	218
Morro Bay Power Plant	1	30.5%	2.1%	0.3%				416,270	28,773	3,824				156	156	156			
	2	34.1%	5.1%	1.2%				465,793	70,032	16,661				156	156	156			
	3	67.6%	18.2%	5.3%	8.5%	6.3%	6.8%	1,776,305	477,710	140,106	223,373	166,175	178,531	300	300	300	300	300	300
	4	55.9%	36.2%	5.3%	4.1%	5.8%	5.6%	1,468,682	952,001	139,114	108,775	153,085	145,994	300	300	300	300	300	300

APPENIX B: Coastal Power Plant Units with Once-Through Cooling

2001-2006 Unit-Level Capacity Factors Calculated Based on CEC QFER Generation Database

		Unit-Level Capacity Factors						Net MWh						MW					
Plant Name	Unit	2001	2002	2003	2004	2005	2006	2001	2002	2003	2004	2005	2006	2001	2002	2003	2004	2005	2006
Moss Landing Power Plant	CC1		29.7%	60.0%	50.2%	50.0%	56.7%		1,403,695	2,839,092	2,376,068	2,365,094	2,682,447		540	540	540	540	540
	CC2		26.0%	53.6%	58.9%	53.2%	56.6%		1,230,641	2,536,060	2,787,905	2,518,509	2,679,697		540	540	540	540	540
	6	57.2%	36.2%	9.0%	5.6%	3.8%	6.2%	3,532,315	2,223,839	554,528	344,032	235,205	380,210	705	702	702	702	702	702
	7	79.9%	27.1%	11.8%	12.0%	3.8%	10.8%	4,914,734	1,664,460	724,555	736,306	231,933	663,004	702	702	702	702	702	702
Ormond Beach Generating Station	1	46.5%	17.7%	11.2%	20.0%	2.0%	0.2%	3,054,687	1,161,114	737,821	1,313,299	133,615	15,939	750	750	750	750	750	806
	2	45.0%	17.9%	16.5%	14.2%	6.0%	6.5%	2,953,302	1,175,626	1,081,400	935,344	391,101	456,997	750	750	750	750	750	806
Pittsburg Power Plant	5	54.4%	19.1%	26.0%	23.1%	12.0%	7.4%	1,548,201	543,207	740,839	657,632	341,666	211,384	325	325	325	325	325	325
	6	62.3%	23.9%	7.0%	20.3%	7.1%	5.2%	1,774,791	681,269	197,881	578,967	202,408	147,870	325	325	325	325	325	325
	7	71.4%	40.9%	16.3%	9.0%	1.7%	1.4%	4,504,836	2,581,405	1,026,447	566,225	108,788	87,997	720	720	720	720	720	720
Potrero Power	3	56.4%	30.0%	45.5%	46.6%	21.3%	28.8%	1,022,727	544,528	824,960	844,596	385,621	521,444	207	207	207	207	207	207
Redondo Beach LLC	5	10.8%	5.4%	8.3%	2.3%	1.0%	1.7%	165,674	83,270	126,838	35,915	14,631	26,960	175	175	175	175	175	179
	6	24.3%	3.1%	1.7%	1.5%	1.1%	1.7%	372,640	47,314	25,810	22,599	17,250	26,225	175	175	175	175	175	175
	7	67.2%	22.8%	12.6%	17.5%	6.6%	6.7%	2,824,702	960,270	529,386	736,394	278,134	287,648	480	480	480	480	480	493
	8	66.7%	23.2%	8.6%	11.1%	2.7%	5.6%	2,802,693	975,607	360,689	467,634	114,197	242,145	480	480	480	480	480	496
San Onofre	2	96.1%	86.1%	98.4%	81.6%	90.5%	68.4%	9,492,023	8,499,969	9,712,482	8,054,877	8,931,731	6,753,997	1127	1127	1127	1127	1127	1127
	3	57.2%	96.7%	87.1%	70.7%	95.9%	69.0%	5,649,799	9,548,152	8,596,269	6,976,282	9,468,279	6,816,843	1127	1127	1127	1127	1127	1127
Scattergood	All	24.8%	16.5%	31.7%	24.8%	13.6%	21.3%	1,743,859	1,160,981	2,227,165	1,741,384	956,572	1,498,069	803	803	803	803	803	803
South Bay Power Plant	1	51.5%	35.5%	34.1%	43.6%	45.9%	32.5%	613,499	423,016	406,292	519,153	546,285	387,083	136	136	136	136	136	136
	2	51.2%	37.3%	39.2%	51.3%	35.8%	29.7%	610,371	444,848	466,938	611,512	427,043	353,689	136	136	136	136	136	136
	3	31.0%	16.2%	22.2%	29.8%	23.6%	7.0%	569,850	298,819	409,023	548,004	434,765	128,967	210	210	210	210	210	210
	4	9.6%	4.1%	2.5%	12.5%	6.7%	4.8%	179,238	77,007	46,489	234,612	125,877	89,415	214	214	214	214	214	214