Scoping Document:

Water Quality Control Policy on the Use of Coastal and Estuarine Waters For Power Plant Cooling

State Water Resources Control Board
California Environmental Protection Agency

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LIST OF ABBREVIATIONS

BPJ – Best Professional Judgment

BTA – Best Technology Available

CARB – California Air Resources Control Board

CDS – Comprehensive Demonstration Study

CEC – California Energy Commission

CEQA – California Environmental Quality Act

CWA – Clean Water Act

CWC – California Water Code

CWIS – Cooling Water Intake Structure

HPF – Habitat Production Foregone

I/E – Impingement and Entrainment

MW – Megawatts

NPDES – National Pollutant Discharge Elimination System

NPHR – Net Plant Heat Rate

NYCRR – New York State Codes Rules and Regulations

OAL – Office of Administrative Law

OPC – Ocean Protection Council

OTC – Single pass, or “Once-through Cooling”

PIC – Proposal for Information Collection

USEPA – United States Environmental Protection Agency

INTRODUCTION

Background

Annually, thermal electric power plants take in billions of gallons of water for cooling and, in the process, impinge and entrain enormous numbers of fish and aquatic organisms. In California alone, it is estimated that coastal and estuarine power plants impinge 9 million and entrain 79 billion fish and other organisms on an annual basis. Since 1972, the Clean Water Act has required in section 316(b) that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. To date, however, efforts by the United States Environmental Protection Agency (USEPA) to adopt regulations implementing section 316(b) for existing power plants have been largely unsuccessful. The State Water Resources Control Board (State Water Board) is therefore considering the development of a state policy for water quality control to establish requirements for implementing section 316(b) for existing coastal and estuarine power plants.

Proposed Project and Description

Note that the State Water Board previously released a Scoping Document titled "Proposed Statewide Policy on Clean Water Act Section 316(b) Regulations" on June 13, 2006. However, because USEPA suspended the requirements for cooling water intake structures at Phase II existing facilities on July 9, 2007, the regulatory landscape for section 316(b) has substantially changed.

This scoping document is intended to provide the public with a preliminary proposal for a state policy (draft attached in Appendix A) and supporting documentation. This scoping document will describe the current status and biological impacts of power plants situated along the California coastline and within coastal estuaries. The purpose of the proposed project is to describe the rational and support for a statewide policy to implement section 316(b) of the Clean Water Act.

Statement of Goals

To adopt a statewide policy to implement Clean Water Act section 316(b) that controls the harmful effects of once through cooling water intake structures on marine and estuarine life.

STATUS OF COASTAL POWER PLANTS IN CALIFORNIA

In California, 21 power plants rely on once-through cooling (OTC) for electrical energy production. These coastal plants are situated in ocean, bay, and estuary environments and are permitted to use up to 17 billion gallons of OTC water each day. Table 1 provides a summary of California's OTC power plants.

Table 1. Information for OTC Power Plants in California

RB [a]	Facility Name	Technology[b]	Agency	Design Flow (MGD[c])	Intake Water Body	Receiving Water Body
1	Humboldt Bay Power Plant [d]	ST	PG&E Company	78	Humboldt Bay	Humboldt Bay
2	Hunters Point Power Plant [e]	ST	PG&E Company	413	San Francisco (SF) Bay	SF Bay
2	Pittsburg Power Plant	ST	Mirant Delta, LLC	676	Sacramento/San Joaquin Delta	Sacramento/San Joaquin Delta
2	Potrero Power Plant	ST/CT	Mirant Potrero, LLC	505	San Francisco Bay	San Francisco Bay
3	Diablo Canyon Power Plant	ST	PG&E Company	2670	Ocean	Ocean
3	Morro Bay Power Plant	ST	LS Power	668	Morro Bay Harbor	Ocean
3	Moss Landing Power Plant	ST/CC	LS Power	1226	Moss Landing Harbor	Ocean
4	Alamitos Generating Station	ST	AES Alamitos, LLC	1282	Los Cerritos Channel	San Gabriel River Estuary
4	El Segundo Generating Station [f]	ST	NRG Energy	607	Ocean (Santa Monica Bay)	Ocean (Santa Monica Bay)
4	Haynes Generating Station	ST/CC	Los Angeles Department of Water and Power (LADWP)	1014	Alamitos Bay	San Gabriel River Estuary
4	Long Beach Generating Station [g]	CT	Long Beach Generation LLC	265	Back Channel, Long Beach Harbor	Long Beach Harbor
4	Harbor Generating Station	CC	LADWP	108	Los Angeles Harbor	Los Angeles Harbor
4	Mandalay Generating Station	ST/CT	Reliant Energy Mandalay LLC	255	Channel Islands Harbor	Ocean
4	Ormond Beach Generating Station	ST	Reliant Energy Mandalay LLC	688	Ocean	Ocean
4	Redondo Generating Station	ST	AES Redondo Beach LLC	1146	Ocean (Santa Monica Bay)	Ocean (Santa Monica Bay)
4	Scattergood Generating Station	ST	LADWP	496	Ocean (Santa Monica Bay)	Ocean (Santa Monica Bay)
5S	Contra Costa Power Plant	ST	Mirant Delta LLC	450	Sacramento/San Joaquin Delta	Sacramento/San Joaquin Delta
8	Huntington Beach Generating Station	ST	AES Huntington Beach, LLC	516	Ocean	Ocean
9	Encina Power Plant [h]	ST	NRG Energy	860	Agua Hedionda Lagoon	Ocean
9	San Onofre Nuclear Generating Station (SONGS) Unit 3	ST	Southern California Edison (SCE)	1287	Ocean	Ocean
9	SONGS Unit 2	ST	SCE	1287	Ocean	Ocean
9	SONGS Unit 1 [i]	N/A	SCE	14	Ocean	Ocean
9	South Bay Power Plant [j]	ST/CT	LS Power	602	San Diego Bay	San Diego Bay
			Total Flow (BGD):	17.1		

a. Regional Water Quality Control Board (Regional Water Board)
b. Technology: ST = Steam Boiler, CC = Combined Cycle, CT = Combustion Turbine Peaker.
c. Million gallons per day
d. Humboldt Bay Power Plant has initiated a re-powering project which will replace the existing units using OTC with new units which do not use OTC.
e. Hunters Point Plant ceased power production on May 15, 2006.
f. NRG Energy has announced its intent to convert the El Segundo Power Plant to closed-cycle cooling (Daily Breeze, March 3, 2007).
g. Long Beach Generating Station ceased power production recently.
h. Planned conversion of plant to CC with dry cooling.
i. SONGS Unit 1 ceased power production in 1992.
j. South Bay Power Plant had initiated a re-powering project which would replace the existing units using OTC with new units which do not use OTC; however, South Bay Power Plant has withdrawn the application for re-powering.

Table 2 summarizes OTC flow in billion gallons per day (BGD) and power production in megawatt-hours (MWh) for California.

Table 2. Flow and Power Production Summary for OTC Power Plants[a]

	2000	2001	2002	2003	2004	2005
OTC Average Flow (BGD)[b]	12.6	13.5	11.0	10.3	10.0	9.4
Gross OTC Power Produced (GWh)[c]	88,099	93,517	67,220	62,833	57,740	56,483
Total Power Generated from all sources (Gigawatt-hours (GWh))[d]	280,496	265,059	272,509	276,969	289,359	287,977
OTC % of CA Power	31	35	25	23	20	20

a. Does not include data for Humboldt Bay, Hunters Point, and Long Beach power plants.
b. For certain power plants, OTC flow data were not obtained for every year. OTC flow data for these power plants were approximated using a long-term average ratio of flow to MWh calculated using all available data. For example, OTC flow data may have only been collected for 2001-2005 for a particular power plant. Year 2000 annual OTC flow for this power plant would be approximated using the average flow/MWh relationship calculated for 2001-2005. Year 2000-2003 flows for SONGS Units 2 and 3 were estimated using the average of 2004 and 2005 flows.
c. Provided by the California Energy Commission (CEC). Downloaded from USEPA's Clean Air Markets website: http://www.epa.gov/airmarkets/emissions/raw/index.html. Power generation data based on gross plant output.
d. Total electrical power use for California from all in-state and out-of-state generation. Source: California Energy Commission website.

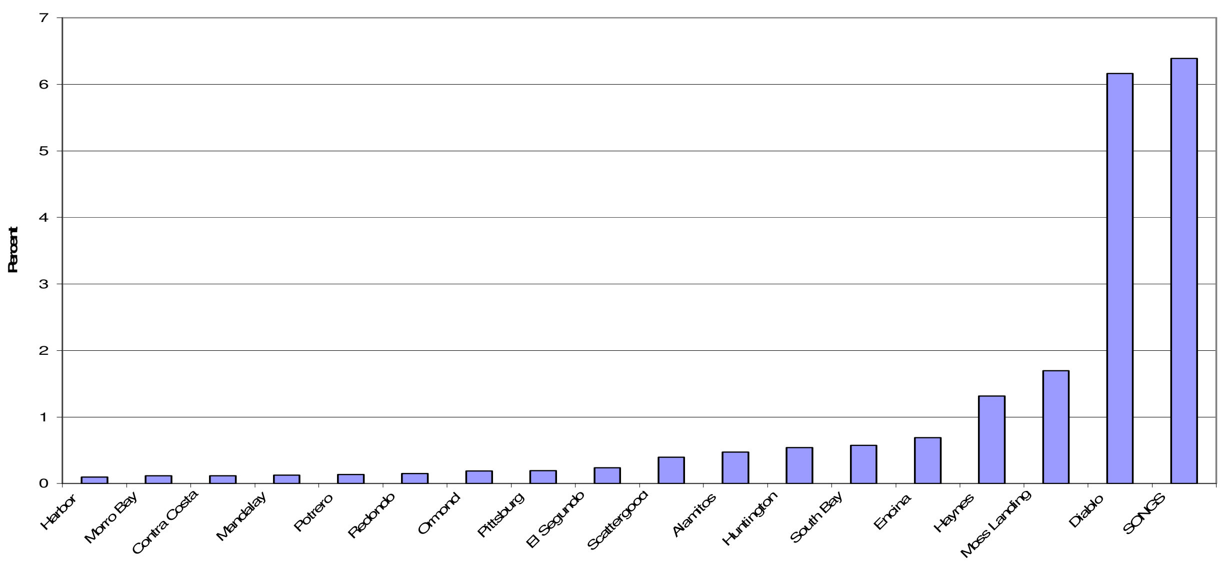
Collectively, the OTC power plants produce a sizable fraction of California's power, as large as 35 percent in 2001. Also shown in Table 2 is that the fraction of State power generated by OTC power plants seem to be trending downward with time, producing only 20 percent in 2005. It is also important to note that the California Independent Systems Operator Corporation (CAISO) forecasts that 1000 megawatts (MW) of new generation must be added each year just to keep pace with the State's increasing demand for electricity[1].

Figure 1 shows the percent each OTC power plant provided towards the total power generated for California in 2005. Note that some OTC power plants provide a small contribution to total power when compared with the total power generated for use by the

State. At first glance, it appears that these power plants may not be essential to the overall reliability of the electrical grid. This assumption may not be true for all cases. For example, some of these power plants provide essential power during peak time periods and/or provide voltage support so that power can be reliably imported from other sources (i.e. hydroelectric, solar, wind, out of state generators, etc.)[a].

The CEC and CAISO have initiated an aging power plant study to determine which of the OTC power plants are essential for grid reliability. The study will also provide a plan for the retirement of the aging/inefficient power plants aligned with the commissioning of new power plants that will help to maintain the reliability of the electrical grid[1]. Even though the OTC power plants did not provide as much power to the grid in 2005 as they have in the past, it is evident from the CAISO comments and similar comments from the CEC[b] that the fleet of OTC power plants are essential to the overall reliability of the grid, especially in light of the fact that the State's demand for electricity is increasing[1].

Figure 1. Percent of Total Power Production, OTC Power Plants in Calif. (2005[a])



a. OTC power generation data based on gross plant output.

Power Plant Utilization

A measure of a power plants' overall utilization is the capacity utilization rate (CUR). USEPA's 316(b) regulations define the CUR as the ratio between the average annual net generation of power by the facility (in MWh) and the total net capability of the facility to generate power (in MW) multiplied by the number of hours during a year. In cases where a facility has more than one intake structure, and each intake structure provides cooling water exclusively to one or more generating units, USEPA states that the CUR

[a] Jim Detmers. CAISO Comment Letter – Proposed Statewide Policy for Once-Through Cooling. September 15, 2006.
[b] Jackalyne Pfannenstiel. California Energy Commission Comments on the State Water Resources Control Board Scoping Document and Proposed Statewide Policy on Clean Water Act 316(b) Regulations. September 26, 2006.

may be calculated separately for each intake structure, based on the capacity utilization of the units it services. USEPA further constrained the CUR definition to only include that portion of the facility that generates electricity for transmission or sale using a thermal cycle with a steam water system as the thermodynamic medium.

In general, the CUR is the ratio of the power generated to the total power that a plant could have generated operating at full capacity. Table 3 summarizes OTC power plant electricity generation capacities by intake structure (e.g., Alamitos units 1 and 2 are served by the same intake structure).

Table 3. OTC Power Plant/Unit Electricity Generation Capacities

Plant Units	Generation Technology[a]	Capacity (MW)[b]
Alamitos 1&2	ST	350
Alamitos 3&4	ST	640
Alamitos 5&6	ST	960
Contra Costa	ST	680
Diablo	Nuc	2269
El Segundo 1&2	ST	350
El Segundo 3&4	ST	670
Encina 1-5	ST	929
Harbor	CC	240
Haynes 1&2	ST	444
Haynes 3&4	ST	444
Haynes 5&6	ST	682
Haynes 9&10	CC	575
Huntington	ST	880
Mandalay	ST	430
Morro	ST	1002
Moss 1-4	CC	1020
Moss 6&7	ST	1509
Ormond	ST	1500
Pittsburg 5&6	ST	650
Potrero	ST	207
Redondo 5&6	ST	350
Redondo 7&8	ST	963
Scattergood	ST	803
SONGS[c] 2	Nuc	1123
SONGS 3	Nuc	1109
South Bay	ST	690

a. Technology: ST = Steam Boiler, CC = Combined Cycle, Nuc = Nuclear.
b. Capacities provided by the CEC.
c. SONGS

For this analysis, USEPA's definition for CUR was used to calculate utilization for all OTC power plants except combined cycle power plants. Also, gross plant output data were used instead of net plant output data to compute the utilization (the difference between gross and net output have not been considered in this analysis). For combined cycle power plants, USEPA's definition states that the power generated and capacity of the combustion turbine should be neglected (i.e. only use the steam turbine heat recovery power/capacity). However, CEC staff suggested that combined cycle systems should be considered one distinct generating unit. Thus, in this analysis, the capacity and power generated by a combined cycle system are considered the sum of the capacity and generation of both the steam and combustion turbines.

USEPA defines a peaker plant as a power plant with an annual CUR of less than 0.15, or 15 percent[c]. Per USEPA's definition, CURs were averaged among units served by the same intake structure. For example, the CUR for Alamitos Units 1 and 2 is the MWh weighted average of the CUR of each unit taken separately.

Table 4 summarizes the 2005 annual average and the 2000-2005 long-term average percent CURs for the OTC power plants. Note that the 2000-2005 average CURs are much higher than the 2005 average annual CURs. In 2005, 14 plants/units (as determined by intake structure) had a CUR of 15 percent or less, while for the 2000-2005 period only four plants/units fell into this category.

Table 4. 2000-2005 Percent Capacity Utilization Rates of OTC Power Plants[a]

Plant/Units	2005 CUR(%)	2005 USEPA Peaker[b]	2000-2005 CUR(%)	2000-2005 USEPA Peaker[b]
Alamitos 1&2	3	Y	9	Y
Alamitos 3&4	8	Y	30	N
Alamitos 5&6	10	Y	30	N
Contra Costa	6	Y	28	N
Diablo	89	N	85	N
El Segundo 1&2	--	--	10	Y
El Segundo 3&4	12	Y	27	N
Encina 1-5	24	N	36	N
Harbor	14	Y	26	N
Haynes 1&2	21	N	31	N
Haynes 3&4	--	--	9	Y
Haynes 5&6	10	Y	18	N
Haynes 9&10	47	N	47	N
Huntington	20	N	21	N
Mandalay	10	Y	34	N
Morro Bay	4	Y	23	N
Moss 1-4	49	N	38	N
Moss 6&7	4	Y	30	N
Ormond	4	Y	22	N
Pittsburg 5&6	10	Y	29	N

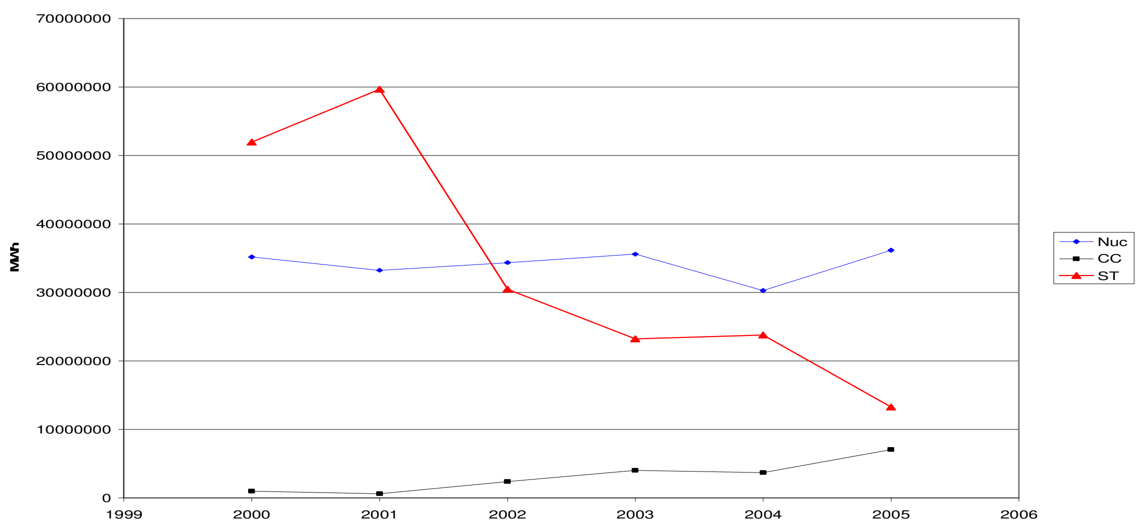
[c] Federal Register/Vol. 69, No. 131/Friday, July 9, 2004/Rules and Regulations, page 41616.

Plant/Units	2005 CUR(%)	2005 USEPA Peaker[b]	2000-2005 CUR(%)	2000-2005 USEPA Peaker[b]
Potrero	22	N	44	N
Redondo 5&6	1	Y	7	Y
Redondo 7&8	5	Y	26	N
Scattergood	16	N	25	N
SONGS 2	90	N	89	N
SONGS 3	98	N	89	N
South Bay	27	N	30	N

a. Power generation based on gross plant output.
b. Federal Register/Vol. 69, No. 131/Friday, July 9, 2004/Rules and Regulations, page 41616. USEPA defines a peaker plant as a plant with less than 15 percent overall utilization.

Figure 2 shows the annual OTC power produced by generation technology for 2000-2005 [steam boiler (ST), nuclear (Nuc), and combined cycle power (CC) plants]. The steam boiler MWh are trending downward, combined cycle MWh are trending upward, and nuclear MWh are relatively constant for the time period.

Figure 2. OTC Power Generation by Technology[a]



a. Technology: ST = Steam Boiler, CC = Combined Cycle, Nuc = Nuclear. Power generation based on gross plant output. Does not include data for Humboldt Bay, Hunters Point, and Long Beach Power Plants.

Power Plant Efficiencies

While steam boilers are generally less efficient than combined cycle systems, they are typically more efficient than stand alone combustion turbines (typically used as peaker plants)[d]. However, the steam boiler systems require a cold source to reject heat from the steam cycle, which in the case of OTC power plants is the ocean, bay, or estuary that the cooling water is drawn from and discharged to.

[d] USEPA Section 316(b) Phase II Technical Development Document, Section 5.2.1.

One measure of the plant thermal efficiency used by the power industry is the Net Plant Heat Rate (NPHR), which is the ratio of the total fuel heat input (BTU/hr) divided by the net electric generation (kW). The net electric generation includes only electricity that leaves the plant. The total plant energy efficiency can be calculated from the NPHR using the following formula[4]:

$$\%eff = \frac{3413}{NPHR} \times 100$$

Table 5 presents the NPHR and plant efficiency numbers for different types of power plants[4].

Table 5. Heat Rates and Plant Efficiencies of Steam Powered Plants[a]

Plant Type	NPHR (BTU/kWh)	% Efficiency
Steam Turbine - Fossil Fuel[b]	9,355	37 to 40
Steam Turbine – Nuclear	10,200	34
Combined Cycle – Gas	6,762	51
Combustion Turbine	11,488	30

a. Source: Analyzing Electric Power Generation under the CAAA. Office of Air and Radiation U.S. Environmental Protection Agency. April 1996 (Projections for year 2000-2004).
b. Data are for coal fired plants.

Installation of alternative cooling systems (cooling towers or dry cooling) would likely lower the average efficiencies of the State's OTC power plants. USEPA estimates the overall energy penalty for a steam boiler fossil fuel power plant with OTC versus cooling towers/dry cooling to be on the order of 1.7/8.6 percent of plant power output, while for a combined cycle power plant the estimated energy penalty for OTC versus cooling towers/dry cooling is 0.4/2.1 percent[e].

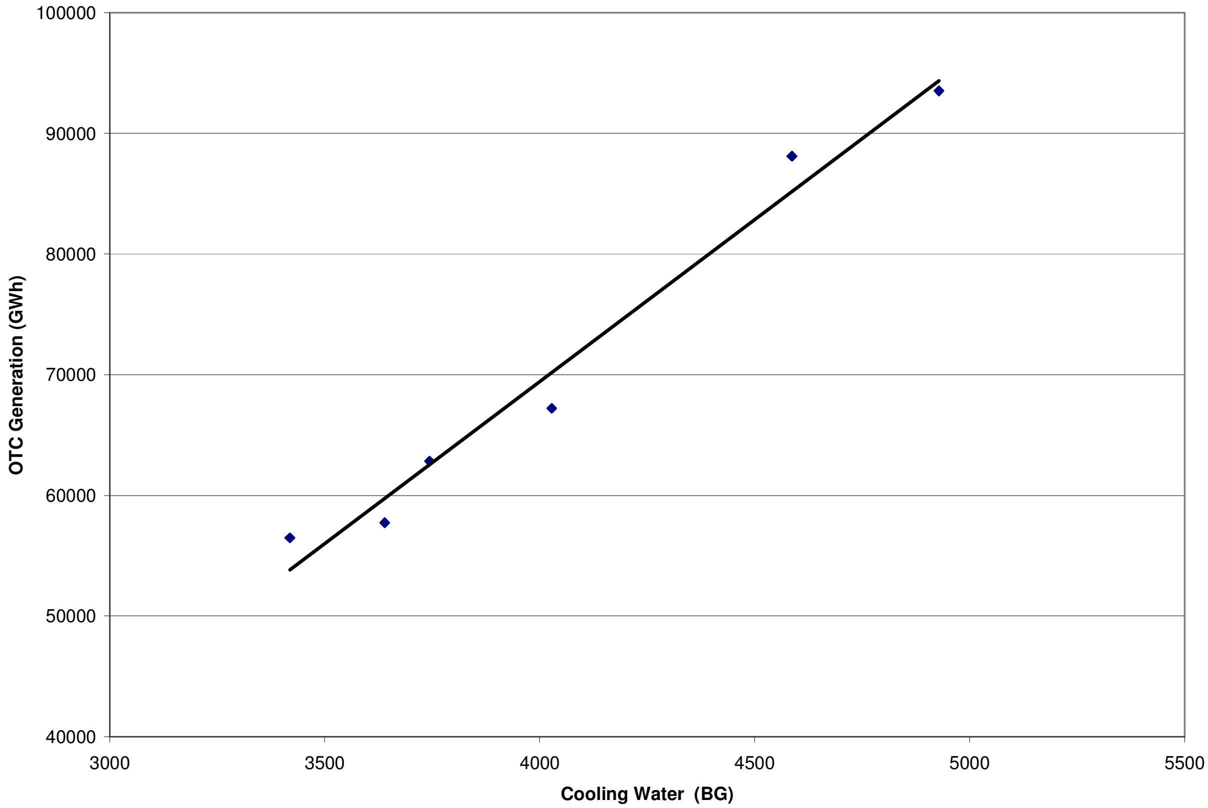
Cooling Water Flows

As shown by the flow and power generation data in Table 2, OTC power plants utilize a significant amount of cooling water. In Figure 3, the 2000–2005 combined annual cooling water flows versus power generation are plotted. Figure 4 shows that the total OTC power generation and cooling water flow are linearly correlated.

While Figure 3 shows that significant OTC water is used for the generation of electricity and that overall cooling water flow and power generation are directly correlated, it does not show that the amount of OTC water used per MWh produced can be dramatically different from one power plant to another. Figure 4 shows the long-term average ratio of OTC flow to power generated for power plants in California. The lower the flow to power generation ratio, the less cooling water is used per MWh generated.

[e] National average, mean-annual energy penalty, USEPA Section 316(b) Phase II Technical Development Document, Section 5.1.

Figure 3. 2000-2005 Combined Annual Cooling Water Flow Data Versus Total Power Generated[a]

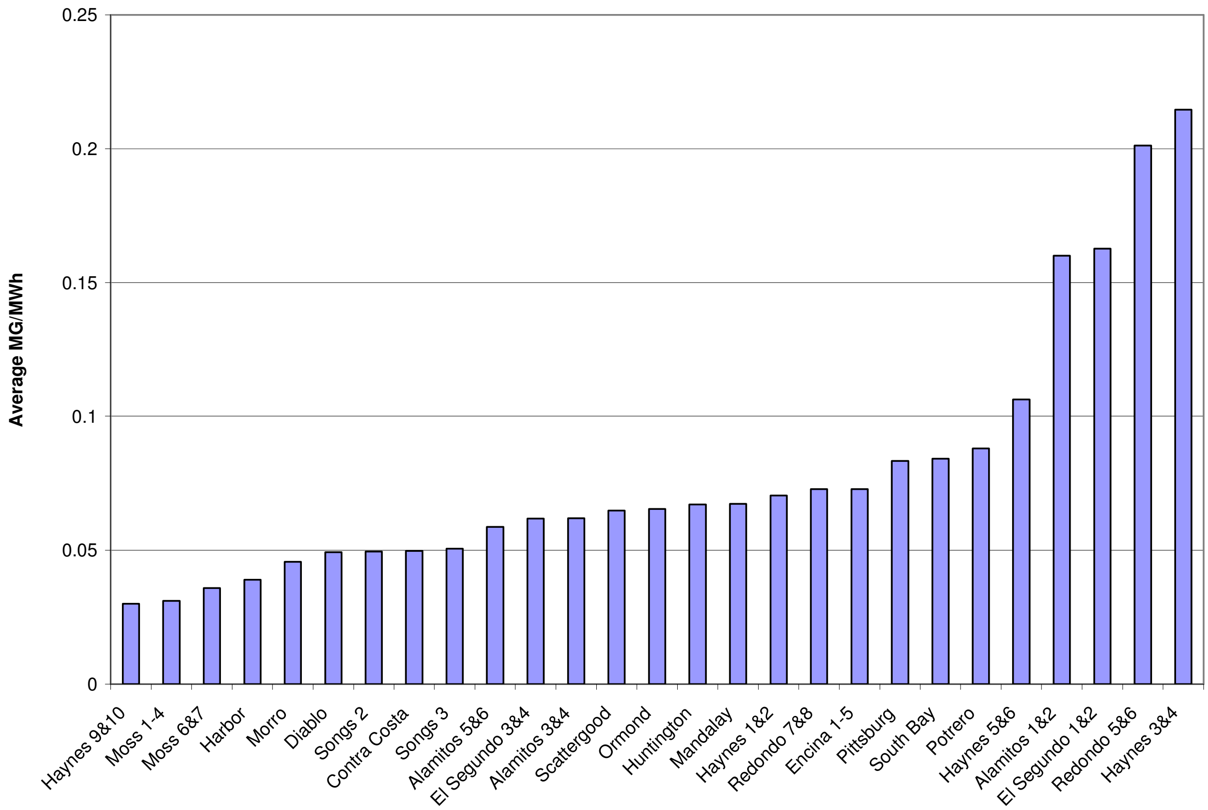


a. Power generation based on gross plant output. Does not include data for Humboldt Bay, Hunters Point, and Long Beach power plants.

Figure 4 shows that the volume of cooling water required per MWh generated is highly variable between power plants and that, in general, combined cycle power plants use less cooling water per MWh generated than steam boiler systems (Haynes 9&10, Moss 1-4, and Harbor power plants/units have some of the lowest MG:MWh ratios). In some cases, cooling water flow to MWh ratios are elevated because of cooling water system operation without the production of power.

In order to determine the actual cooling water flows at each OTC power plant, it is important to consider that some of these plants are being operated more heavily during peak power demand periods. Table 6 presents the 2001 (highest dataset annual OTC power generation) and 2005 (lowest dataset annual OTC power generation) monthly median cooling water flows for OTC power plants during summer (June-September) and winter conditions (October – May).

Figure 4. Average Cooling Water Flow: Power Generation Ratios for OTC Power Plants[a]



a. Based on OTC flow and generation data for 2000-2005. Power generation is based on gross plant output.

Table 6. Monthly Median Cooling Water Flows

Plant/Units	2001 Median Monthly Flows (MG)		2005 Median Monthly Flows (MG)	
	October-May	June-September	October-May	June-September
Alamitos 1&2	3214	6324	1326	1518
Alamitos 3&4	12059	11865	6117	6418
Alamitos 5&6	20892	20555	2696	10212
Contra Costa	8877	10144	1288	5468
Diablo	74743	75823	75823	75538
El Segundo 1&2	3987	1234	1543	1580
El Segundo 3&4	6287	10472	5175	6279
Encina 1-5	17919	21462	16915	15022
Harbor	2136	1936	1507	1666
Haynes 1&2	5751	7619	5990	8321
Haynes 3&4	7392	8280	--	--
Haynes 5&6	9254	12682	10865	11372
Haynes 9&10	--	--	6422	6891

Plant/Units	2001 Median Monthly Flows (MG)		2005 Median Monthly Flows (MG)	
	October-May	June-September	October-May	June-September
Huntington	a	a	7487	13643
Mandalay	7729	7729	7145	6985
Morro	15160	18004	453	5004
Moss 1-4	--	--	9958	10151
Moss 6&7	18902	22697	103	5212
Ormond	20591	20937	4772	13100
Pittsburg	21884	29786	914	6452
Potrero	6348	6838	2344	6447
Redondo 5&6	a	a	605	1335
Redondo 7&8	a	a	128	6612
Scattergood	8177	11389	7609	10818
SONGS 2	a	a	37269	37167
SONGS 3	a	a	37776	37167
South Bay	12468	13491	11927	11585

a. Flow data for these power plants were not obtained for this year.

Many of the power plants have greater cooling water flows during the months of June-September as compared with October-May flows (see Table 6).

State Water Board staff examined graphs of cooling water flow versus power generation for most of the OTC power plants. For many power plants, cooling water flow increases with power generation; however, many of the relationships are not correlated very well.

Baseline Air Emissions

The California Air Resources Control Board (CARB) has evaluated baseline air emissions from two types of hypothetical power plants, a 300 MW steam turbine power plant unit and a 540 MW combined-cycle power plant unit, both fueled by natural gas[f].

Table 7 shows the baseline emissions inventory for the hypothetical 300 MW steam turbine power plant unit and the hypothetical 540 MW combined-cycle power plant unit cooled by OTC.

Table 7. Estimated Baseline Air Emissions from OTC Power Plants

Technology	Greenhouse Gas (tons/yr)	Criteria Pollutants (tons/yr)					
	CO_2[a]	TOG[b]	ROG[c]	NOX[d]	SOX[e]	CO[f]	$PM_{2.5}$[g]
Steam Turbine (300 MW)	235,196	18.19	7.84	52.55	1.84	150.29	16.59

[f] California Air Resources Control Board 6/1/07 memo to State Water Board.

	Greenhouse Gas (tons/yr)	**Criteria Pollutants (tons/yr)**					
Combined Cycle (540 MW)	790,213	61.10	26.35	176.5	6.18	504.93	55.72

a. carbon dioxide
b. total organic gases
c. reactive organic gases
d. nitrogen oxides
e. sulfur oxides
f. carbon monoxide
g. 2.5 micron particulate matter

BIOLOGICAL AND CUMULATIVE IMPACTS FROM ONCE THROUGH COOLING

Entrainment and Impingement

Impacts associated with OTC include impingement, entrainment, and thermal effects. The biological impacts of OTC may not be adequately known since modern quantitative studies are difficult and costly. Seawater, however, is not just cool water but a highly productive and diverse aquatic habitat.

OTC power plants are generally the largest volume dischargers in the state, ranging from 78 to 2670 MGD. The largest volumes are associated with the active nuclear generating stations, Diablo Canyon and San Onofre, with design flows of 2,670 and 2,587 MGD respectively. The largest volume for a conventional power plant is for the Alamitos power plant, at 1282 MGD (design flow). Discharge volumes roughly correspond to intake volumes. By comparison, the largest wastewater treatment plant with an ocean discharge is the Hyperion wastewater plant (City of Los Angeles), which has a permitted flow of 420 MGD; most ocean dischargers of treated sewage are well below 50 MGD, including the City of San Francisco's Oceanside plant discharge (43 MGD).

The effluent limits for marine and estuarine wastewater discharges under National Pollutant Discharge Elimination System (NPDES) permits (including power plant discharges) are designed to prevent acute and chronic toxicity to marine aquatic life, thereby protecting fish and other marine life from mortality. When spills and industrial discharges do result in fish kills, in violation of the California Water Code and the Fish and Game Code, enforcement actions are typically taken. Ironically, with all of the limitations and prohibitions placed on discharges, impingement and entrainment have essentially constituted a permitted fish kill for power plant intake systems.

There has been an historical emphasis on commercially or recreationally important species, primarily fish. The reality is, however, that a power plant cooling system does not discriminate and instead causes mortality to all aquatic life in the water column community. Protection of the entire ecological community is essential for promoting a healthy ecosystem.

San Onofre Nuclear Generating Station (SONGS) represents one example of imgingement and entrainment (I/E) impacts. Fish enter the SONGS cooling water system through an offshore cooling water intake, with a velocity cap, and then through a screenwell to the fish return system. Those fish that do not enter the fish return system are impinged on traveling screens. An estimated 3.6 million fish were impinged in 2003 at SONGS. Fish species impinged included northern anchovy, queenfish, Pacific sardine, Pacific pompano, jacksmelt, white seaperch, walleye surfperch, shiner perch, white croaker, bocaccio, jack mackerel, salema, sargo, yellowfin croaker, specklefin midshipman, black perch, California grunion, topsmelt, cabezon, deep body anchovy, and others. No estimates are available for impinged invertebrates at SONGS. Annual entrainment of fish larvae at SONGS is estimated to be nearly 6 billion. This figure does not include invertebrate plankton, which are also entrained (Proposal for Information Collection, San Onofre Nuclear Generating Station, Southern California Edison, prepared by Dave Baily, EPRI Solutions Inc., October 2005).

As another example, the Diablo Canyon Nuclear Generating Station draws seawater directly from an intake cove and through the shore-based intake structure. While impingement mortality is less than at SONGS, due to the difference in structural and environmental systems, entrainment is still significant. Diablo Canyon impacts an average source water coastline length of 74 kilometers (46 miles) out to 3 kilometers (2 miles) offshore, an area of roughly 93 square miles, for nine taxa of rocky reef fish. These rocky reef fish included smoothhead sculpin, monkeyface prickleback, clinid kelpfishes, blackeye goby, cabezon, snubnose sculpin, painted greenling, Kelp/Gopher/Black-and-Yellow (KGB) Rockfish Complex, and blue rockfish. In that 93 square mile source water area, an average estimated proportional mortality of 10.8 percent was calculated for these rocky reef taxa. The rocky reef fish species with the largest calculated coastline impact was the smoothhead sculpin, having an estimated proportional mortality of 11.4 percent over 120 kilometers (75 miles) of coastline during a 1997-98 sampling period (Diablo Canyon Power Plant Independent Scientist's Recommendations to the Regional Water Quality Control Board, Item no. 15 Attachment 1, Sept. 9, 2005 Meeting).

As an example of a conventional power plant, the South Bay Power Plant in San Diego Bay, assuming full operation, has an estimated annual impingement of 390,000 fish, 93 percent of which were anchovies. Impingement of certain invertebrates was also assessed at this plant; an estimated 9,019 crustaceans (shrimps, lobsters, crabs) and cephalopods (octopus and squid) were impinged annually. Annual estimated entrainment for 2003 was 2.4 billion fish larvae. Fish species most represented in the entrainment studies were gobies (arrow, cheekspot, and shadow), anchovy, combtooth blennies, longjaw mudsuckers, and silversides (Tenera, South Bay Power Plant PIC, 2005).

Using various data sources, State Water Board staff estimated the total impingement and entrainment from power plants using once-through cooling. Table 8 shows estimates of actual numbers and biomass of aquatic life impinged and entrained from California's coastal and estuarine power plants. The values in Table 8 are absolute annual estimates and were not adjusted to adult equivalents.

Table 8. Estimates of Annual Impingement and Entrainment at California's Coastal and Estuarine Power Plants.

Power Plant	Group	Impinge-ment Count (#/year)	Impinge-ment Mass (kg/year)	Entrainment Count (#/year)	Notes/Data Source
Humboldt Bay Power Plant	fish	n/e	n/e	n/e	Will repower with dry cooling
Hunters Point Power Plant	fish	n/e	n/e	n/e	Ceased power production on May 15, 2006
Pittsburg Power Plant	fish	381,515	2,191	468,220,000	E-PIC 2006 Tbl 4-1
Pittsburg Power Plant	inverts	3,089,908	2,577	12,095,100,000	I- PIC 2004 Tbls 4-2
Pittsburg Power Plant	eggs	n/e	n/e	1,970,000	E-PIC 2006 Tbl 4-1
Potrero Power Plant	fish	7,515	190	291,942,194	E-Potrero PIC 2006, Tbl 4-1
Potrero Power Plant	inverts	199,686	255	n/e	I - PIC Tbl 4-2 for Unit 3 only. Mar '78-79. Invert count incl. jellyfish via PIC appx Tbl 2
Diablo Canyon Power Plant	fish	402	504	1,833,010,000	DC Entrainment Findings, Steinbeck et al 2006 - Tbl 3-18
Diablo Canyon Power Plant	inverts	n/e	184	n/e	DC Impingement from 3/1/00 316(b) Demo Report * - actual number collected, kg is estimated total for the year;
Diablo Canyon Power Plant	tetrap	1	n/e	n/e	Ca Sea Lion 2001, 2004, 2005 from J. Cordaro, NMFS, Long Beach, CA 8/15/06
Morro Bay Power Plant	fish	73,825	1,144	508,296,000	E-Steinbeck 2006, Tbl 3-6
Morro Bay Power Plant	inverts	52,949	360	n/e	I-Findings Section 316(b) Modernized Morro Bay Power Plant Tables 4-2 and 4-3 values for estimated totals. Note that invertebrates only include crabs, shrimps, octopus, and squid
Moss Landing Power Plant	fish	176,332	1,194	345,000,000	I - from '05-'06 Study - Units 1, 2,6, 7 Note that invertebrates only include crabs, shrimps, octopus, and squid; E-est based on fish density in CECreport and 2005 flow
Moss Landing Power Plant	inverts	146,270	413	210,700	E - est based on crab density in CECreport and 2005 flow
Alamitos Generating Station	fish	28,082	503	1,686,757,809	May 2007 LA DWP meeting material
Alamitos Generating Station	inverts	11,338	462	4,329,954	May 2007 LA DWP meeting material
Alamitos Generating Station	eggs	n/e	n/e	606,607,376	May 2007 LA DWP meeting material
El Segundo Generating Station	fish	945	174	n/e	May 2007 LA DWP meeting material
El Segundo Generating Station	inverts	49,793	94	n/e	May 2007 LA DWP meeting material

Power Plant	Group	Impinge-ment Count (#/year)	Impinge-ment Mass (kg/year)	Entrainment Count (#/year)	Notes/Data Source
Haynes Generating Station	fish	6,694	73	3,645,939,849	May 2007 LA DWP meeting material
Haynes Generating Station	inverts	2,682	37	14,845	May 2007 LA DWP meeting material
Haynes Generating Station	eggs	n/e	n/e	1,684,934,099	May 2007 LA DWP meeting material
Long Beach Generating Station	fish	n/e	n/e	n/e	Ceased power production recently
Harbor Generating Station	fish	1,290	189	65,297,999	May 2007 LA DWP meeting material
Harbor Generating Station	inverts	1,014	37	18,901,336	May 2007 LA DWP meeting material
Harbor Generating Station	eggs	n/e	n/e	99,884,894	May 2007 LA DWP meeting material
Mandalay Generating Station	fish	124,721		2,268,000,000	Mandalay Revised PIC
Mandalay Generating Station	inverts	210	n/e	n/e	Mandalay Revised PIC
Ormond Beach Generating Station	fish	24,424	n/e	1,925,000,000	Mandalay Revised PIC
Ormond Beach Generating Station	inverts	9,493	n/e	n/e	Mandalay Revised PIC
Ormond Beach Generating Station	tetrap	2	n/e	n/e	J. Cordaro, NMFS, Long Beach, CA 8/15/06
Redondo Generating Station	fish	340	38	245,467,974	May 2007 LA DWP meeting material
Redondo Generating Station	inverts	367	42	27,049,393	May 2007 LA DWP meeting material
Redondo Generating Station	eggs	n/e	n/e	2,860,520,400	May 2007 LA DWP meeting material
Scattergood Generating Station	fish	87,845	3,989	365,258,133	May 2007 LA DWP meeting material
Scattergood Generating Station	inverts	24,296	316	27,322,839	May 2007 LA DWP meeting material
Scattergood Generating Station	eggs	n/e	n/e	4,919,422,026	May 2007 LA DWP meeting material
Scattergood Generating Station	tetrap	5	n/e	n/e	J. Cordaro, NMFS, Long Beach, CA 8/15/06
Contra Costa Power Plant	fish	110,359	1,666	95,110,000	PIC, data for Units 6&7 only
Contra Costa Power Plant	inverts	200,371	226	3,493,830,000	PIC, data for Units 6&7 only
Contra Costa Power Plant	eggs	n/e	n/e	12,800,000	PIC, data for Units 6&7 only
Huntington Beach Gen. Station	fish	51,082	1,292	254,877,299	PIC Attch B, 2003-2004 study
Huntington Beach Gen. Station	inverts	70,638	168	473,628,497	PIC Attch B, 2003-2004 study
Encina Power Plant	fish	79,662	3,076	26,200,000,000	PIC p. 3-6, 1979-80
Encina Power Plant	inverts	4,862	n/e	n/e	PIC p. 3-6
Encina Power Plant	eggs	n/e	n/e	4,710,000,000	PIC p. 3-6, 1979-80
Encina Power Plant	tetrap	2	n/e	n/e	J. Cordaro, NMFS, Long Beach, CA 8/15/06

Power Plant	Group	Impinge-ment Count (#/year)	Impinge-ment Mass (kg/year)	Entrainment Count (#/year)	Notes/Data Source
San Onofre – Songs Unit 2&3	fish	3,564,433	21,924	5,668,000,000	I-PIC Attch A, 2003 study, E-CEC June2005
San Onofre – Songs Unit 2&3	tetrap	47	n/e	n/e	J. Cordaro, NMFS, Long Beach, CA 8/15/06
South Bay Power Plant	fish	385,588	556	2,420,528,000	I - SB PIC, p. 28 E- Steinbeck et al 2006, Tbl 3-1 2001 study
South Bay Power Plant	inverts	9,019	23	n/e	I - SB PIC, p. 28 E- Steinbeck et al 2006, Tbl 3-1 2001 study

"n/e" indicates no estimate available
"tetrap" indicates a tetrapod impingement (i.e., seals, sea lions, or sea turtles)

Table 9 shows a summary of the combined impingement and entrainment for all California coastal and estuarine power plants. In summary, each year California power plants impinge about 9 million biological specimens having a mass of approximately 44,000 kg (97,000 lbs). California power plants also annually entrain about 80 billion biological specimens, of which approximately 60 percent (48 billion) are larval fish. In addition, 57 marine tetrapods (seals, sea lions, or sea turtles) are impinged annually. Of these tetrapods, roughly 50 percent are killed.

Table 9. Total Annual Impingement and Entrainment from all Coastal and Estuarine Power Plants in California.

Biological Group	Impingement Count (#/year)	Impingement Mass (kg/year)	Entrainment Count (#/year)
fish	5,105,054	38,703	48,286,705,257
invertebrates	3,872,896	5,194	16,140,387,564
aquatic life eggs	n/e	n/e	14,896,138,795
tetrapods	57	n/e	n/e
All Groups Combined	8,978,007	43,898	79,323,231,616

"n/e" indicates no estimate available

Cumulative Impacts

A study performed by MBC and Tenera in 2005 estimated that, for 12 coastal power plants in the Southern California Bight, there is an overall cumulative entrainment mortality of 1.4 percent. In the same study, for eleven coastal power plants in the Southern California Bight the estimated cumulative impingement was approximately 3.6 million fish. Considering only recreational fish species, impingement was somewhere between 8-30 percent of the number of fish caught in the Southern California Bight (CEC, Issues and Environmental Impacts Associated with Once-Through Cooling at California's Coastal Power Plants, 2005).

The cumulative effects of closely situated power plants withdrawing cooling water from a water body is an area in need of research. If OTC continues to be used by plants in close proximity on the same water body, a cumulative ecological study should be considered. This is especially important in the Southern California Bight where many power plants are situated within several miles from each other. Plant-specific impacts associated with the use of OTC occur in conjunction with other anthropogenic impacts in a regional area. A cumulative impact analysis will consider the presence and impacts of other power plants in a regional area. Closely situated facilities may wish to coordinate their monitoring studies in order to better evaluate broad cumulative effects. Generally, individual effects of several power plants can be expected to be additive. However, multiple reductions in the population of a sensitive species may produce species population declines greater than the simple sum of each facility's impact.

As an example, a reduction in the numbers of a particular aquatic fish species due to mortality at a single power plant may be small. A nearby power plant may also cause a small mortality. However, the combined effect of mortality at both plants may exceed a threshold needed for sustained, long-term populations of the species.

Threatened, Endangered, and Protected Species

Threatened, endangered, and protected species in the source water body of a power plant pose special considerations. Fish and wildlife agencies, such as the National Oceanic and Atmospheric Administration (NOAA), National Marine Fisheries Service (NMFS), US Fish and Wildlife (USFW), and the California Department of Fish and Game, often participate in the permitting process and attempt to determine if the facility will cause or contribute to an adverse impact on essential habitat for threatened or endangered species.

Under the Endangered Species Act, the term "take" is defined to mean harass, harm, pursue, hunt, shoot, wound, kill, trap, capture, or collect, or to attempt to engage in any such conduct. Under the Marine Mammal Protection Act (MMPA), the term "take" means to harass, hunt, capture, or kill, or attempt to harass, hunt, capture, or kill any marine mammal. Incidental taking is defined as an unintentional, but not unexpected, taking. Harassment under the 1994 Amendments to the MMPA is statutorily defined as any act of pursuit, torment, or annoyance which *(Level A Harassment)* has the potential to injure a marine mammal or marine mammal stock in the wild; or, *(Level B Harassment)* has the potential to disturb a marine mammal or marine mammal stock in the wild by causing disruption of behavioral patterns, including, but not limited to, migration, breathing, nursing, breeding, feeding, or sheltering but which does not have the potential to injure a marine mammal or marine mammal stock in the wild.

Marine mammals such as sea otters, sea lions, and harbor seals, and even marine reptiles (endangered sea turtles), have become trapped in power plant intake structures. After extraction, marine mammals do not always survive. For this reason some power plants have applied for incidental take permits from the USFW and NMFS.

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 [316(b) PIC for Mirant Contra Costa Power Plant, Tenera Environmental, April 2006]. Site-specific impacts such as these must be minimized and ultimately mitigated.

LEGAL AND REGULATORY REQUIREMENTS

California Water Code and Current State Water Board Policy

The Porter-Cologne Water Quality Control Act (Porter-Cologne)[g], enacted in 1969, is the primary water quality law in California. Porter-Cologne addresses two primary functions – water quality control planning and waste discharge regulation. Porter-Cologne is administered regionally, within a framework of statewide coordination and policy. The state is divided into nine regions, each governed by a Regional Water Quality Control Board (Regional Water Board).

The State Water Board oversees and guides the Regional Water Boards through several activities, including the adoption of statewide water quality control plans[h] and state policy for water quality control[i]. The State Water Board-adopted California Ocean Plan, for example, designates ocean waters for a variety of beneficial uses, including rare and endangered species, marine habitat, fish spawning and migration and other uses, and establishes water quality objectives to protect those uses.[j] The State Water Board is also charged with adopting state policy for water quality control, which may consist of principles or guidelines deemed essential by the State Water Board for water quality control.[k]

In addition to State Water Board-adopted policies, Porter-Cologne contains state law for the coastal marine environment. Like section 316(b), Water Code section 13142.5, requires that any new or expanded coastal powerplant using seawater for cooling to use "the best available site, design, technology, and mitigation measures feasible . . . to minimize the intake and mortality of all forms of marine life."

The Regional Water Boards adopt water quality control plans for all waters, including coastal waters, bays, and estuaries, if appropriate, within their regions. These plans must conform to state policy for water quality control.

Under Porter-Cologne, the State and Regional Water Boards regulate waste discharges that could affect water quality through waste discharge requirements.[l] In addition, the state is authorized to issue NPDES permits to point source dischargers of pollutants to navigable waters. In 1972, the California Legislature amended Porter-Cologne to provide the state the necessary authority to implement an NPDES permit program in lieu of a USEPA-administered program under the Clean Water Act.[m] To ensure consistency with Clean Water Act requirements, Porter-Cologne requires that the Water Boards issue and administer NPDES permits to ensure compliance with all applicable

[g] Wat. Code §13000 et seq.
[h] See *id.* §13170.
[i] See *id.* §13140 et seq.
[j] California Ocean Plan (2005), chs. 1 & 2.
[k] Wat. Code §13142.
[l] See *id.* §§13263, 13377.
[m] Wat. Code, div. 7, ch. 5.5.

requirements of the Clean Water Act.[n] The State Water Board is designated as the state water pollution control agency under the Clean Water Act and is authorized to exercise any powers delegated to the state by the act.[o] [p]

To date, the State Water Board has not adopted any state policies for water quality control or plans to implement §316(b) or Water Code §13142.5. Over 30 years ago, the State Water Board adopted a policy on the use of fresh inland surface waters for power plant cooling. The policy in Resolution No. 75-58, titled "Water Quality Control Policy on the Use and Disposal of Inland Waters Used for Powerplant Cooling,"[q] was intended to discourage the use of inland water resources for once-through cooling. The 1975 policy favors the use of treated wastewater as cooling water or OTC with seawater in order to conserve fresh inland water resources. The 1975 policy does not address § 316(b) and is significantly out-of-date.

NPDES Permit Status

Table 10 shows the current status of the National Pollutant Discharge Elimination (NPDES) permit for California power plants. Currently, 11 power plants are operating with expired permits. Two plants, Potrero and Harbor, will require renewal in 2008. Four plants are planning to convert to dry cooling: Humboldt, El Segundo Units 1-4, Encina, and South Bay. The Contra Costa Unit 8 plant is a new facility that will employ dry cooling. Two plants, Long Beach and Hunter's Point, are no longer in operation.

Table 10. NDPES Permit Status of Power Plants

RB	Facility Name	Agency	NPDES Permit Adoption Date	NPDES Permit Expiration Date	Permit in Review ?	Notes
3	Diablo Canyon Power Plant	PG&E Company	11-May-90	11-May-95	Y	Pending lawsuit.
3	Morro Bay Power Plant	LS Power	10-Mar-95	10-Mar-00	Y	
2	Hunters Point Power Plant	PG&E Company	18-May-94	18-May-04	N	Permit administratively extended, May 18, 1999. Ceased power production on May 15, 2006.
4	Alamitos Generating Station	AES Alamitos, LLC	29-Jun-00	10-May-05	Y	
4	El Segundo Generating Station	El Segundo Power LLC	29-Jun-00	10-May-05	Y	Will likely file (re-power) for dry cooling
4	Haynes Generating Station	LADWP	29-Jun-00	10-May-05	Y	
4	Redondo Generating Station	AES Redondo Beach LLC	29-Jun-00	10-May-05	Y	
4	Scattergood Generating Station	LADWP	29-Jun-00	10-May-05	Y	
3	Moss Landing Power Plant	LS Power	27-Oct-00	27-Oct-05	Y	

[n] *Id.* §13377; see also Cal. Code Regs., tit. 23, §2235.2.
[o] *Id.* §13160.
[p] *Id.* §§13372, 13377. EPA's permit regulations are contained in 40 C.F.R. parts 122, 123, and 124.
[q] State Water Board Resolution No. 75-58.

RB	Facility Name	Agency	NPDES Permit Adoption Date	NPDES Permit Expiration Date	Permit in Review ?	Notes
4	Mandalay Generating Station	Reliant Energy Mandalay LLC	26-Apr-01	10-Mar-06	Y	
5S	Contra Costa Power Plant	Mirant Delta, LLC	27-Apr-01	1-Apr-06	Y	
4	Long Beach Generating Station	Long Beach Generation LLC	24-May-01	10-Apr-06	N	Ceased power production recently.
1	Humboldt Bay Power Plant	PG&E Company	26-Apr-01	26-Apr-06	Y	has filed (re-power) for dry cooling
4	Ormond Beach Generating Station	Reliant Energy Mandalay LLC	28-Jun-01	10-May-06	Y	
2	Pittsburg Power Plant	Mirant Delta, LLC	19-Jun-02	31-May-07	Y	
4	Harbor Generating Station	LADWP	10-Jul-03	10-Jun-08	N	
2	Potrero Power Plant	Mirant Potrero, LLC	10-May-06	31-Dec-08	N	
9	South Bay Power Plant	NRG Energy	10-Nov-04	10-Nov-09	N	has filed (re-power) for dry cooling
9	San Onofre - SONGS Unit 1	Southern California Edison	09-Feb-00	9-Feb-05	N	Ceased power production in 1992.
9	San Onofre - SONGS Unit 2	Southern California Edison	11-May-05	11-May-10	N	
9	San Onofre - SONGS Unit 3	Southern California Edison	11-May-05	11-May-10	N	
8	Huntington Beach Generating Station	AES Huntington Beach, LLC	14-Oct-06	1-Aug-11	N	
9	Encina Power Plant	NRG Energy	16-Aug-06	1-Oct-11	N	

USEPA CWA Section 316(b) and Federal Regulations

The Clean Water Act (CWA), 33 U.S.C. §1251 et seq., prohibits pollutant discharges from point sources to waters of the United States unless they are regulated under an NPDES permit.[r] Permits are issued by the USEPA or states, such as California, with approved permit programs.[s] The NPDES permit system provides for a two-step process for establishing effluent limitations in permits to regulate pollutant discharges. First, permits must require compliance with technology-based effluent limitations implementing CWA section 301 and section 306.[t] Second, permits must include any more stringent water quality-based limitations necessary to meet water quality standards.[u]

In addition, a permittee with a cooling water intake structure must comply with a separate technological standard established in CWA § 316(b) for the intake structure.[v] CWA section 316(b) states: "Any standard established pursuant to section [301] of this title or section [306] of this title and applicable to a point source shall require that the

[r] 33 U.S.C. §§1311, 1342.
[s] See *id.* §1342.
[t] *Id.* §§1311, 1316.
[u] *Id.* §§1311(b)(1)(C).
[v] *Id.* §1326(b).

location, design, construction, and capacity of cooling water intake structures reflect the BTA for minimizing adverse environmental impact."

In April 1976, USEPA issued a final rule implementing § 316(b).[w] Utility companies successfully challenged the rule in court on procedural grounds, and USEPA withdrew the relevant portions of the rule in 1977. In the absence of federal standards, USEPA and states with approved permit programs, including California, implemented § 316(b) on a case-by-case basis pursuant to CWA section 402(a)(1)(B) using best professional judgment (BPJ).[x]

In 1993, a coalition of environmental groups and individuals sued USEPA over its failure to adopt regulations implementing section 316(b).[y] USEPA eventually entered into a consent decree to settle the litigation and established a timetable to issue rules in three phases. USEPA completed the first phase on November 9, 2001, by promulgating a final rule governing cooling water intake structures for new power plants (Phase I).[z] On July 23, 2004, USEPA promulgated intake regulations for existing power plants (Phase II).[aa] On July 9, 2007, however, USEPA suspended the Phase II rule in response to a remand decision by the United States Court of Appeals for the Second Circuit in *RiverKeeper, Inc. v. USEPA (2nd Cir. 2007) 475 F.3d 83* (*RiverKeeper II*).[bb] USEPA completed the third phase on June 16, 2006.[cc] The Phase III rule addresses new offshore oil and gas extraction facilities.

Phase I Rule

The Phase I rule applies to new electric generating plants and manufacturers that withdraw more than two MGD from waters of the U.S. and use 25 percent or more of their intake water for cooling.[dd] New facilities with smaller cooling water intakes will still be regulated on a site-by-site basis.[ee]

In the Phase I rule, USEPA determined that the BTA for minimizing adverse environmental impacts from cooling water intake structures at new power plants is closed-cycle wet cooling. The Phase I regulations establish a two-track approach for regulating the intake structures.[ff] Track I establishes national intake capacity and velocity requirements based on closed-cycle wet cooling technology, as well as location- and capacity-based requirements to reduce intake flow below certain proportions of certain water bodies (referred to as "proportional-flow requirements"). It also requires the discharger to select and implement design and construction

[w] 41 Fed. Reg. 17387 (April 26, 1976).
[x] 33 U.S.C. §1342(a)(1)(B).
[y] See *Cronin v. Browner* (S.D.N.Y. 1995) 898 F.Supp. 1052.
[z] 66 Fed. Reg. 65338 (December 18, 2001), codified at 40 C.F.R. pt. 125, subpt. I.
[aa] 69 Fed. Reg. 41683 (July 9, 2004), codified at 40 C.F.R. pt. 125, subpt. J.
[bb] 72 Fed. Reg. 37107.
[cc] 71 Fed. Reg. 35040, codified at 40 C.F.R. pt 125, subpt. N.
[dd] 40 C.F.R. §125.81.
[ee] *Id.* §125.80(c).
[ff] *Id.* §125.84.

technologies under certain conditions to minimize impingement mortality and entrainment.[gg] Under Track II, a facility may use any technology as long as the facility can show, in a demonstration study, that the alternative technologies will reduce impingement mortality and entrainment for all life stages of fish and shellfish to levels that are comparable to what would be achieved under Track I.[hh] Alternatively, a facility could comply with Track II through restoration measures designed to address impacts, other than impingement and entrainment, provided that the measures would maintain fish and shellfish in the water body at substantially similar levels to that which would be achieved under Track I.

The Phase I rule also includes a variance provision, which authorizes the permitting agency to impose less stringent requirements than those contained in the rule under two circumstances.[ii] These are: (1) facility-specific data indicates that compliance with the rule would result in compliance costs wholly out of proportion to the costs USEPA considered in establishing the rule; and (2) compliance would result in significant adverse impacts on local air quality, water resources, or energy markets.

Both environmental and industry groups sued USEPA over the validity of the Phase I rule in the Second Circuit Court of Appeals. In 2004, the appellate court issued a decision that largely upheld the Phase I rule but remanded those aspects that authorized a facility to comply with section 316(b) through restoration methods [RiverKeeper, Inc. v. USEPA (2d Cir. 2004) 358 F.3d 174 (RiverKeeper I)]. The court held that the restoration option was clearly inconsistent with Congress' intent that intake structures be regulated directly, based on BTA, and without resort to water quality measurements. In a similar vein, the court rejected industry's challenge to USEPA's assumption that all impingement and entrainment are adverse. Industry had argued that USEPA should only have sought to regulate impingement and entrainment where they have deleterious effects on the overall fish and shellfish populations in the ecosystem. The court ruled that USEPA's approach was eminently reasonable and consistent with Congress selection of a technology-based, rather than a water quality-based approach, for regulating adverse impacts from intake structures.

Phase II Rule

The Phase II rule applied to existing electric generating plants that are designed to withdraw at least 50 MGD and use at least 25 percent of their withdrawn water for cooling purposes.[jj]

In the Phase II rule, USEPA did not select closed-cycle cooling as the BTA for minimizing adverse environmental impacts for existing power plants. Rather, USEPA determined that a "suite of technologies" constituted BTA and established performance standards for reductions in impingement mortality and entrainment based on these

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[gg] *Id.* §125.84(b) & (c).
[hh] *Id.* §125.84(d).
[ii] *Id.* §125.85.
[jj] See 40 C.F.R. §125.91.

technologies. The technologies included fine-and wide-mesh wedgewire screens, aquatic filter barrier systems, barrier nets, fish return systems, and others. The performance standard for impingement required an 80 to 95 percent reduction in the number of organisms pinned against parts of the intake structure from uncontrolled levels.[kk] Similarly, the entrainment standard required a 60 to 90 percent reduction in the number of aquatic organisms drawn into the cooling system from uncontrolled levels.[ll]

The Phase II rule set forth five compliance alternatives for achieving BTA, four of which were based on meeting the performance standards. The fifth compliance alternative allowed a site-specific determination of BTA under two circumstances.[mm] These were: (1) where compliance costs would be significantly greater than the costs considered by USEPA (cost-cost); or (2) where compliance costs would be significantly greater than the benefits of meeting the performance standards (cost-benefit). The rule allowed a facility to meet the performance standards through design, construction technologies, operational measures, or restoration measures, or any combination of these.

On January 25, 2007 the Second Circuit Court of Appeals issued its *RiverKeeper II* decision, remanding several significant provisions of the Phase II rule. The major remanded provisions included USEPA's determination of BTA, the performance standard ranges, the site-specific BTA alternatives based on cost considerations, and the restoration provisions.

- The court remanded USEPA's determination of BTA because it was unclear whether USEPA had improperly engaged in a cost-benefit analysis. USEPA had interpreted BTA as "best technology available commercially at an economically practicable cost" and had stated that an important component of economic practicability was the relationship between the costs of control technology and the associated environmental benefits. The court, however, held that section 316(b) requires that facilities adopt the BTA and that a cost-benefit analysis is not authorized. The court further held that USEPA can consider costs in two limited ways: (1) to determine whether the costs of a technology can reasonably by borne by the industry; and (2) to engage in a cost-effectiveness analysis in determining BTA. The court further held that, in making the initial determination, the most effective technology must be based not on the average Phase II facility, but on the optimally best performing facility.

- The court concluded that USEPA can set performance standards as ranges under certain circumstances. However, the court remanded the regulations because they did not require facilities to achieve the high end of the performance ranges, where possible. The regulations were inadequate because they failed to require facilities to choose technologies that permit them to achieve as much reduction of adverse environmental impacts as is technologically possible.

[kk] *Id.* §125.94(b)(1).
[ll] *Id.* §125.94(b)(2).
[mm] *Id.* §125.94(a)(5).

- As it had in *RiverKeeper I,* the court again ruled that the restoration provisions in the Phase II rule were plainly inconsistent with section 316(b) and its technology-forcing principle.

- The court remanded the cost-cost site-specific alternative, or variance, on procedural grounds. Nevertheless, the court expressed discomfort with the "significantly greater than" standard in the Phase II rule, given the use, historically and in the Phase I rule, of a "wholly disproportionate standard." The court noted that the "significantly greater than" standard posed substantial concerns because cost is not supposed to be a paramount consideration in determining BTA.

- The court remanded the cost-benefit compliance alternative, or variance, because section 316(b) does not authorize a site-specific determination of BTA based on a cost-benefit analysis. The court restated its conclusion in *RiverKeeper I* that the Clean Water Act does not permit USEPA to consider water quality, i.e. wildlife levels in the water body, in making BTA determinations.

Finally, the court reiterated its conclusion in *RiverKeeper I* that USEPA correctly interpreted section 316(b)'s directive to minimize adverse environmental impact to require a reduction in the number of aquatic organisms lost as a result of water withdrawn in intake structures. The court rejected industry arguments that removing large numbers of aquatic organisms from water bodies is not in and of itself an adverse impact. The court characterized industry's argument as urging a water quality standard that focuses on fish populations and consequential environmental harm, a position rejected by Congress in enacting section 316(b).

As stated previously, USEPA suspended the Phase II rule after the *RiverKeeper II* decision.[nn] USEPA did not suspend, 40 CFR §125.90 (b), however. This regulation retains the requirement that permitting authorities, in the absence of nationwide standards, use BPJ to implement CWA section 316(b) on a case-by-case basis.

Current Status

Since 1972, the states have been required to implement section 316(b) for existing facilities with cooling water intake structures on a case-by-case basis. This responsibility has been made more difficult because section 316(b) does not specify any particular technology that facilities must use nor the criteria or methods the states should employ to determine BTA. Over 30 years ago, USEPA issued draft guidance that describes recommended studies for evaluating the impact of cooling water structures on the aquatic environment and recommends a basis for determining BTA.[oo] Likewise, several USEPA General Counsel opinions from the 1970's address

[nn] 72 Fed. Reg. 37107 (July 9, 2007)
[oo] *Draft Guidance for Evaluating the Adverse Impact of Cooling Water Intake Structures on the Aquatic Environment: Section 316(b) P. L. 92-500* (May 1, 1977).

interpretation of section 316(b).[pp] None of these administrative documents is binding on the states, however.

The *RiverKeeper* decisions provide some guidance in interpreting section 316(b). In both decisions, the court held that the cross-reference in section 316(b) to sections 301 and 306 "is an invitation" to look at those sections for guidance in determining what factors USEPA can consider in determining BTA. Based on its analysis of these sections, the court in *RiverKeeper II* held that USEPA cannot base its determination of BTA on a cost-benefit analysis, but that USEPA can consider costs in a limited fashion. The court also cited energy efficiency and environmental impacts as permissible factors in determining BTA. Both *RiverKeeper* decisions conclude that restoration measures are inconsistent with section 316(b).

Recently, a California appellate court upheld the Central Coast Regional Water Board's case-by-case determination of BTA in a permit issued for the Moss Landing Power Plant [*Voices of the Wetlands v. California State Water Resources Control Board* (2007) 157 Cal. App. 4th 1268 (69 Cal. Rptr. 3d 487)]. The permit authorizes the facility to use once-through cooling for two new combined-cycle generating units. The permit required the permittee to upgrade the existing intake structure to minimize impingement impacts. In addition, the permit found that adverse impacts due to the intake system on the watershed will be minimized through environmental enhancement projects in the watershed.

Relying on decision law interpreting section 316(b) on a case-by-case basis, the Central Coast Regional Water Board had determined that the costs of other technologies were wholly disproportionate to the environmental benefits. The appellate court upheld this approach. In addition, the court concluded that the Central Coast Regional Water Board did not improperly use the environmental enhancement plan in lieu of technology to implement section 316(b). Rather, the court found that the Central Coast Regional Water Board had used the plan only as a means to monetize environmental impacts and benefits under the wholly disproportionate test.

Finally, the Water Boards must also consider the legislative directive in Water Code §13142.5 when regulating cooling water intake structures. Under the Clean Water Act, facilities must, at a minimum, comply with section 316(b) requirements and any more stringent applicable requirements necessary to comply with state law. Section 13142.5 has a more limited coverage than section 316(b) in that the former covers only new and expanded coastal facilities. However, section 13142.5 appears to be more stringent than section 316(b) in one respect. Section 13142.5 requires use of the best available technology feasible "to minimize the intake and mortality of all forms of marine life", without regard to whether these impacts are adverse, in contrast to section 316(b) which focuses on "minimizing adverse environmental impact."

[pp] See, e.g., Op. EPA Gen. Counsel (Jan. 17, 1973), stating that the authority to regulate under §316(b) was not dependent on the prior issuance of thermal effluent limitations and that cooling water intake limitations could be imposed under §402(a)(1); Op. EPA Gen. Counsel 63 (July 29, 1977).

Other California State Agencies

The California Energy Commission (CEC) has authority under the Warren-Alquist Act to license thermal power plants with a capacity of 50 megawatts (MW) or more.[qq] The California Coastal Commission is required under the California Coastal Act to participate in the CEC licensing process with the goal of protecting coastal resources and preventing potential adverse environmental effects on fish and wildlife and their habitats.[rr]

The California Coastal Commission has the authority to issue coastal development permits for power plant projects in the coastal zone. The California State Lands Commission has authority over, and is responsible for leasing, state tidelands to coastal power plants.

The California Ocean Protection Council (OPC or Council) has heard testimony on the damaging environmental effects of OTC at power plants. The Council is committed to improving coordination among the various state agencies to ensure that the environmental effects of the use of OTC water are minimized. On April 20, 2006, the Council adopted a Resolution regarding the use of OTC technologies in coastal waters. Among other things, the Resolution called for the following: the formation of a technical review group for reviewing each plant's Clean Water Act § 316(b) study designs, and a study of the technical feasibility of converting to alternative cooling technologies at coastal power plants. In a later decision the OPC decided to partner with the State Water Board in funding the grid reliability study.

Cooling Water Intake Policies of other States

Maryland

Title 26, Subtitle 08, Chapter 03 of the Code of Maryland Regulations requires that "The location, design, construction, and capacity of cooling water intake structures shall reflect the BTA for minimizing adverse environmental impact."

For Phase II facilities, Maryland is including intake structure requirements in NPDES Permits based on BPJ. The BPJ requirements implementing BTA for cooling water intake structures are derived from USEPA's suspended Phase II 316(b) regulations.

New York

There are approximately 30 power plants within the State of New York that are classified as Clean Water Act §316(b) Phase II facilities. These power plants are situated at rivers, lakes, and estuaries, but not on New York's Atlantic coastline. To implement federal 316(b) requirements for Phase II existing facilities, New York is including intake structure requirements in State Pollutant Discharge Elimination System

[qq] Pub. Resources Code §25500 et seq.
[rr] *Id.* §30413(d).

(SPDES) permits (New York equivalent to California NPDES Permits). New York has its own cooling water intake structure regulation at Title 6, New York State Codes Rules and Regulations (NYCRR), Section 704.5, which reads:

"The location, design, construction and capacity of cooling water intake structures, in connection with point source thermal discharges, shall reflect the best technology available for minimizing adverse environmental impact."

The New York State Department of Environmental Conservation's cooling water intake structure regulations give broad discretion to the permitting agency in the determination of BTA. New York's intake requirements included in discharge permits will be at least as stringent as those of USEPA's Phase II 316(b) regulations. Additionally, the following requirements are imposed under 6 NYCRR 704.5:

a. *Restoration.* Restoration plans are not considered an appropriate or acceptable BTA alternative for any facility, new or existing.

b. *Site-specific alternative BTA determination.* The suspended Phase II minimum performance standards (i.e. 80 percent reduction in impingement and 60 percent reduction in entrainment) represent the minimum allowed, and the permitting authority (New York) will seek to impose the higher end of these ranges.

To determine whether a facility is meeting or will meet impingement and entrainment reduction standards, New York compares the estimated number of organisms impinged and entrained after deployment of technologic or operational reduction measures with a baseline when the facility is operating at full flow and full generation capacity.

The New York State Department of Environmental Conservation has not issued new correspondence to USEPA regarding the regulation of Phase II facilities since USEPA announced intentions to suspend the Phase II regulations. Department of Environmental Conservation staff has indicated that they will continue to regulate Phase II facilities under state authority and that they will seek to impose the highest achievable reduction in entrainment and impingement as BTA.

Wisconsin

Chapter 283.31(6), Wisconsin Statutes, allows the Wisconsin Department of Natural Resources, Bureau of Watershed Management, to require that the location, design, construction, and capacity of cooling water intake structures reflect the BTA for minimizing adverse environmental impact.

The Director of the Bureau of Watershed Management issued a guidance memo to Wisconsin permit writers on February 22, 2005 that provides direction for implementing state statute and the federal Phase II regulations. The guidance memo indicates that the state intends to implement the federal 316(b) regulations for the determination of state and federal BTA for cooling water intake structures. Wisconsin's Director of the

Bureau of Watershed Management has not issued new guidance regarding the regulation of Phase II facilities since USEPA announced intentions to suspend the Phase II requirements.

At this time Wisconsin is including intake structure requirements in NPDES Permits based on BPJ.

Michigan

The State of Michigan developed guidance for CWA 316(b) intake studies in 1975. Michigan's 1975 guidance, titled *Thermal and Intake Studies – Guidance Manual*, provides information for:

- Conducting CWA 316(a) Thermal Discharge Demonstrations
- Conducting CWA 316(b) Intake and Entrapment Demonstrations
- Representative and Important Species

Michigan's comprehensive guidance manual is available online for reader review at: http://www.deq.state.mi.us/documents/deq-wb-permits-316bguidance.pdf.

ALTERNATIVES TO OTC

Alternative technologies are available that can reduce or eliminate the impacts of OTC. The CEC evaluated alternatives to OTC in Chapter 6 of its June 28, 2005 report. The CEC identifies the following alternative technologies:

- Dry Cooling
- Closed Cycle Wet Cooling Towers
- Using alternative cooling water sources – recycled wastewater

Details regarding the above alternative technologies can be found in the CEC's June 28, 2005 report, which is available at: http://www.energy.ca.gov/2005publications/CEC-700-2005-013/CEC-700-2005-013.PDF.

Four of the coastal power plants are completely or partially ceasing the use of OTC and re-powering with dry cooling (Humboldt Bay, Encina, Long Beach, and El Segundo, which is planning to install dry cooling on the portion of its plant). Depending on the water source and waste disposal infrastructure available, dry cooling may not involve an intake or discharge of water and therefore may not require an NPDES permit.

The use of wastewater as a direct cooling water medium (i.e., a direct substitution for ocean or estuarine waters) is limited by geographic, business, and regulatory constraints. This potential strategy is dependent on local conditions, including the relative locations of the sewage treatment and power plant, the land use between the treatment plant and the power plant, the quantity and quality of the treated wastewater, and the location, or depth and structural attributes of the outfall. The movement of treated wastewater to a power plant would require significant engineering and construction pipelines. In most cases, where candidate wastewater and power plants are not adjacent, the intervening land use is also a consideration. Heavily urbanized areas may require underground pipes to connect the treatment plant to the power plant. If deep-water ocean discharge would be necessary, then pipelines in both directions would be required.

Cooling water flows are typically much larger than treated wastewater volumes. In addition, wastewater may not be as cold as ocean or bay water, thereby reducing the efficiency of heat transfer. Therefore, there are likely only limited or no situations in which wastewater could completely substitute for ocean water, but there may be some cases where treated wastewater may be used to reduce the amount of water withdrawn for OTC.

Power plant outfalls are often in shallow water. If treated wastewater is used for cooling at a power plant, a discharge of heated, treated waste water to a beach or shallow outfall may pose unacceptable risks to beneficial uses such as contact recreation or protection of marine aquatic life (e.g., kelp forests).

A nearly ideal situation would be one in which a wastewater treatment plant is located in very close proximity to a power generating facility, and in which both facilities are owned or operated by the same municipality. One example of such a circumstance is the City of Los Angeles Hyperion Wastewater Treatment Plant and the Scattergood generating facility, operated by the Los Angeles City Department of Water and Power. Hyperion discharges approximately 420 MGD of secondary treated wastewater, while Scattergood's flow is approximately 496 MGD, so the volumes are roughly similar. Hyperion discharges its wastewater far from shore at a depth of 187 feet below sea level, while Scattergood discharges at a depth of only 15 feet near shore. If treated wastewater were used to partially substitute or even replace OTC marine water, the wastewater may need to be returned to Hyperion for deep-water discharge. Heating the wastewater would increase the buoyancy of the plume, thereby modifying the initial dilution characteristics.

According to the CEC's 2005 report "Issues and Environmental Impacts Associated with Once-through Cooling at California's Coastal Power Plants," a re-powering project was proposed and approved by the Energy Commission for the El Segundo generating plant site in Los Angeles County. The El Segundo power plant is located within 1.25 miles of the Hyperion Wastewater Treatment Plant. The Energy Commission staff estimated the Hyperion plant as having a capacity of 450 MGD, whereas the El Segundo re-powering facility proposed to use 207 MGD ocean water for cooling. Due to concerns about entrainment impacts of OTC, Energy Commission staff proposed that the El Segundo power plant use the Hyperion wastewater for cooling and return the water to the waste treatment facility after use. Capital costs were estimated to be $12 million. Operation cost was expected to be slightly greater due to efficiency loss, at a cost of $1 - 2 million dollars per year. It was expected that some cost would also be incurred to purchase the wastewater, but this was not negotiated with the City of Los Angeles. Apparently the City did not indicate a willingness to sell the treatment plant wastewater to the power plant at that time.

OPC ALTERNATIVE COOLING SYSTEM ANALYSIS

The Alternative Cooling System Analysis OPC study conducted by Tetra Tech (February 2008) evaluates the logistical, regulatory, and economic factors that arise when a facility modifies its cooling water system by implementing technology-based measures designed to achieve the OPC performance benchmark. The report moves beyond a model-based approach by using facility-specific data to develop comprehensive cost and engineering profiles that are unique to each of California's affected facilities. It is not, however, intended to be exhaustive in terms of the many obstacles that may exist and the different technology configurations that can be evaluated, nor can it be considered a substitute for the more rigorous engineering assessment that would be conducted prior to the implementation of one of the evaluated options. Instead, the intent is to establish a more precise understanding of the associated costs of a once-through cooling system retrofit, and the factors that influence those costs, in order to assist state agencies in the regulatory development process as it moves forward.

The Tetra Tech study shows that retrofitting with wet cooling systems could be *technically and logistically feasible* at 12 of the 15 active coastal power plants. Twelve plants where wet cooling towers (retrofits) were considered technically and logistically feasible by Tetra Tech were: Alamitos, Contra Costa, Diablo Canyon, Harbor, Haynes, Huntington Beach, Mandalay, Morro Bay, Moss landing, Pittsburg, SONGS, and Scattergood. The three plants where wet cooling towers (retrofits) were considered technically and logistically infeasible by Tetra Tech were Redondo, Ormond Beach, and El Segundo.

Retrofitting to wet cooling towers is not feasible at Redondo Beach because of its immediate proximity to office buildings and residential areas. Compliance with local use requirements would be unlikely. For two other facilities – El Segundo and Ormond Beach – the preferred option could not be configured to meet the minimum site constraints. At both locations, interference from a wet cooling tower's visible plume with nearby flight operations made it probable that plume-abated towers would be required. An acceptable configuration could not be designed for either location due to limited space availability and potential interference with other major structures. In addition, at El Segundo, the cooling towers would be located immediately adjacent to the beach, which may conflict with the requirements the California Coastal Act to protect visual resources.

Likewise, Ormond Beach is infeasible given the limited space at the site. While it appears that there is sufficient space for conventional towers, the Tetra Tech analysis suggested plume-abated towers because of the proximity to the Naval Air Station (~2 miles downwind) and the potential for significant impact from a visible plume. However, plume abated towers require more room for placement than conventional towers, and there may not be sufficient space at that location. The recent agreement with the Nature Conservancy removed a substantial portion of the facility as a conservation easement.

At Diablo Canyon and San Onofre—retrofitting is problematic (although not necessarily infeasible). At Diablo Canyon, the constraints of the existing site and the disruption a wet cooling tower retrofit will require both units to be offline for 8 months or more. At San Onofre, the installation and operation of wet cooling towers would require an additional regulatory approval because of a potential effect on sensitive plant species and environmentally sensitive habitats.

IMPINGEMENT/ENTRAINMENT CONTROL TECHNOLOGIES ASSOCIATED WITH OTC SYSTEMS

Variable Speed Pumps/ Variable Frequency Drives - Allow a facility to moderate its cooling water intake flow depending on seasonal and operational conditions. The maximum benefit is dependent on reductions in intake flow but actual reductions will be based on the time of year and generating load of the facility. Variable speed pumps are technically feasible at all facilities; a benefit, however, is dependent on the frequency and degree which flow can be reduced without impacting operations.[ss]

Traveling Water Screens – Traveling Water Screens have been employed on seawater intakes since the 1890's. The screens are equipped with revolving wire mesh panels having 6mm to 9.5mm openings. As the wire mesh panels revolve out of the flow, a high-pressure water spray removes accumulated debris, washing it into a trough for further disposal. The screens are located onshore, either as a shore installation on an embayment or at the end of a channel, forebay or pipe that extends out beyond the surf zone into the sea.[tt] Traveling screens located onshore within an embayment, with intake velocities of less than 0.5 feet per second, are considered acceptable controls to eliminate impingement.

Velocity Cap – The cover placed over the vertical terminal of an offshore intake pipe is called a "velocity cap". The cover converts vertical flow into horizontal flow at the intake entrance to reduce fish entrainment. It has been noted that fish will avoid rapid changes in horizontal flow and velocity cap intakes have been shown to provide 80-90% reduction in fish impingement at two California power stations, and a 50-62% impingement reduction versus a conventional intake at two New England power stations

[ss] California's Coastal Power Plants: Alternative Cooling System Analysis, prepared by Tetra Tech, Inc, February 2008

[tt] Pankratz, Tom: An Overview of Seawater Intake Facilities for Seawater Desalination www. texaswater.tamu.edu/readings/desal/Seawaterdesal.pdf

(EPA Efficacy of Cooling Water Intake Structures, EPA-821-R-01-036, November 2001, http://www.epa.gov/waterscience/316b/phase1/technical/ch5.pdf).

It has been shown that the relationship of the vertical opening (x) to the length of horizontal entrance (1.5x) can be optimized to create a uniform flow and improve a fish's ability to react. As with all intake configurations, there are many design issues that must be considered, and the performance of a velocity cap may vary in still water versus areas subject to tidal cross-flows.[uu] Even with velocity caps, offshore intakes have been known to allow impingement of marine wildlife.

Fish Return Systems – A **Ristroph *Screen*** is a modification of a conventional traveling water screen in which screen panels are fitted with fish buckets that collect fish and lift them out of the water where they are gently sluiced away prior to debris removal with a high pressure spray. At one New York seawater intake, the 24-hour survival of conventional screens averaged 15% compared with 79-92% survival rates for Ristroph Screens. A review of 10 similar sites reported that Ristroph modifications improved impingement survival 70-80% among various species. Ristroph Screens may be effective for improving the survival of impinged marine life, but they do not affect entrained organisms. **Fish Elevators** remove fish from within a forebay prior to impingement on traveling screens. The fish are then returned to the sea. In California, SONGS operates a fish return system with a fish elevator.

Fine Mesh Screens have successfully reduced entrainment of eggs, larvae, and juvenile fish at some intake locations where traveling water screens have been outfitted with mesh having openings ranging from 0.5 mm to 5 mm, reducing entrainment by up to 80%. Fine mesh screens may result in operational problems due to the increased amount of debris removed along with the marine life, and in some locations, the fine mesh is only utilized seasonally, during periods of egg and larval abundance.[vv]

Passive "Wedgewire" Screens – Another intake arrangement utilizes slotted screens constructed of trapezoidal- shaped "wedgewire". The cylindrical screens have openings ranging from 0.5 millimeters (mm) to 10 mm are usually oriented on a horizontal axis with screens sized to maintain a velocity of less than 15 centimeter per second (cm/s) (0.5 feet per second, fps) to minimize debris and marine life impingement. Passive screens are best-suited for areas where an ambient cross-flow current is present, and air backwash system is usually recommended to clear screens if debris accumulations do occur. As with all submerged equipment, material selections should reflect the corrosion and biofouling potential of seawater.

Passive screens have a proven ability to reduce impingement and entrainment in river systems. Their effectiveness is related to their slot width, and low through-flow velocity. It has been demonstrated that 1 mm openings are highly effective for larval exclusion

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uu Ibid

vv Ibid

and reduce entrainment by 80% or more.[ww] Wedgewire screen systems have not been employed or tested in open coastal waters, or in any California waters to date.

Filter Net Barriers are a relatively new method of reducing intake impingement and entrainment. A full-depth, porous filter fabric with openings ranging from 0.4mm to 5mm is placed at the entrance to an intake structure and suspended by a floating boom and anchored to the seabed. The system is sized to provide enough surface area to have a through-flow velocity low enough to avoid impingement of marine life or debris. [xx] If placed in an embayment such net barriers would pose safety risks to the navigation beneficial use or possibly eliminate the use. Filter net barriers have not been employed or tested in open coastal waters, or in any California waters to date.

Behavioral systems using lights, bubbles, or sound to enhance fish avoidance or attract them to a fish diversion system have generally been ineffective and are used infrequently.[yy]

See Appendix B for a table of existing intake and control information at California's OTC power plants.

DESALINATION AND POWER PLANTS

Seawater desalination increasingly supplements water supply needs in coastal California communities. New desalination technologies have made desalination more feasible. However, desalination requires a great amount of electricity and creates waste brine. Disposal of waste brine is problematic because the salinity can be twice the salinity of the ocean. Waste brine is denser than seawater and has the potential to sink to the ocean bottom, adversely impacting sensitive benthic organisms.

Because of the energy and waste disposal needs, desalination facilities are increasingly being proposed at or near existing coastal power plants. Co-location allows the desalination facility to combine (i.e., *co-mingle*) their brine wastes with the large volumes of once-through cooling water used at coastal power plants. In addition, co-location allows the desalination plant to have a reliable and direct use of electrical power produced at the power plant.

Environmental advocates have argued that the co-location of a desalination facility near a power plant will ensure the continued existence of OTC at the power plant, and possibly prolonging the lifetime of an out-dated power plant and its associated environmental impacts. Power plant officials recognize that their main business is to generate electric power, not to provide water, and the co-location of a desalination facility near a power plant must have community support and not hinder the power

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ww Ibid
xx Ibid
yy Ibid

plant's current or future operations. A stand-alone desalination facility will be required to apply for an NPDES permit to discharge waste brine.

Typically, desalination plants co-located with power plants draw water off of the system after thermal exchange and, therefore, should not increase the intake volumes. This subject is outside of the scope of the Clean Water Act § 316(b) issues and would be more appropriately addressed under existing water quality control plans and policies (e.g., California Ocean Plan, State Water Board Policy for Implementation of Toxics Standards for Inland Surface Waters, Enclosed Bays, and Estuaries of California).

ISSUES AND ALTERNATIVES FOR STATEWIDE CWA 316(B) POLICY

Should the State Water Board Adopt a Statewide Policy?

Although most of the Phase II rule was remanded to USEPA and suspended, 40 CFR 125.90 (b) was not suspended. This retains the requirement that permitting authorities implement CWA Section 316(b) on a case-by-case basis using BPJ for existing facility cooling water intake structures.

Alternatives:

1. Wait for USEPA to promulgate a new Phase II rule, or
2. Move forward and develop a statewide policy.

Discussion:

USEPA is moving forward with promulgation of a new Phase II rule. It is State Water Board staff's understanding that USEPA will attempt to issue a draft Phase II rule by the end of 2008. Even if the draft is issued by the end of 2008, the formal public comment process and development of a final rule will likely be lengthy.

The development of a statewide policy in California is much further ahead than the USEPA process. California has many plants that need NPDES permits renewed, and that NPDES renewal is contingent upon waiting for a new nationwide rule or a California specific statewide policy. The most expedient way to provide guidance to permit writers for renewal of power plant NPDES permits is through a California statewide policy.

Staff recommendation:

Staff recommends Alternative 2, moving forward with a statewide policy to provide statewide consistency in implementing CWA Section 316(b) and California Water Code Section 13142.5(b).

How should New and Existing Power Plants be defined?

Section 316(b) requires that the location, design, construction, and capacity of cooling water intake structures reflect BTA for minimizing adverse environmental impacts. USEPA implemented §316(b) by developing separate rules for new power plants, existing power plants, and offshore oil and gas extraction facilities. As stated previously, however, the regulations for existing power plants have largely been suspended.

Alternatives:

1. Use the existing definitions as defined by USEPA in the Phase I federal regulations.
2. Create new definitions of new and existing power plants.

Discussion:

Generally there are no truly new coastal power plants being developed in California's coastal waters (marine and estuarine) that rely on once-through cooling. Re-powering projects are essentially new projects at existing power plants.

California Water Code §13142.5 applies to new and expanded coastal power plants. Section 13142.5 does not define the terms "new" or "expanded". However, the USEPA Phase I 316(b) regulations at 40 C.F.R. 125.83 define new facilities as follows:

> "*New facility* means any building, structure, facility, or installation that meets the definition of a "new source" or "new discharger" in 40 C.F.R. 122.2 and 122.29(b)(1), (2), and (4) and is a greenfield or stand-alone facility; commences construction after January 17, 2002; and uses either a newly constructed cooling water intake structure, or an existing cooling water intake structure whose design capacity is increased to accommodate the intake of additional cooling water. New facilities include only "greenfield" and "stand-alone" facilities. A greenfield facility is a facility that is constructed at a site at which no other source is located, or that totally replaces the process or production equipment at an existing facility. A stand-alone facility is a new, separate facility that is constructed on property where an existing facility is located and whose processes are substantially independent of the existing facility at the same site. New facility does not include new units that are added to a facility for purposes of the same general industrial operation (for example, a new peaking unit at an electrical generating station)."

Thus, under the Phase I definition, a new power plant must, at a minimum, be a greenfield or a stand-alone facility, and it must use a new intake structure or an existing structure that has been modified to increase its design capacity to accommodate the intake of additional cooling water. An "existing facility", under the Phase I regulations, is any facility that is not a new facility (40 C.F.R. §125.83.).

Staff recommendation:

State Water Board staff recommends Alternative 1. Under this approach, a new power plant is defined as any plant that is a new facility, as defined in 40 C.F.R. §125.83, that is subject to Subpart I, Part 25 of the Code of Federal Regulations. In like manner, an existing power plant is defined as any power plant that is not a new power plant.

What Constitutes BTA for Existing Power Plants?

In the absence of applicable federal regulations implementing section 316(b), the states and USEPA must use BPJ to determine BTA on a case-by-case basis. The *Riverkeeper* decisions provide some bounds for the exercise of BPJ. First, BTA cannot be determined on the basis of a cost-benefit analysis, although some limited cost consideration is permitted, *i.e.,* can the costs of a given technology be reasonably borne by the industry? Second, the BTA standard is technology-driven; therefore, restoration is not a permissible compliance alternative. Third, the technology must be the "best" technology available, i.e. it must be based on "the optimally best performing" facility and not the average facility. Fourth, other factors, such as the negative environmental impacts of alternative cooling technologies and concerns about energy production and efficiency, may also be considered.

Finally, section 316(b) requires that the technology be the best available for "minimizing adverse environmental impact." Water Code section 13142.5, in contrast, requires that new and expanded industrial facilities using seawater for cooling employ the best available technology feasible "to minimize the intake and mortality of all forms of marine life," irrespective of whether these impacts are adverse.

Alternatives for existing power plants:

1.a. Based on a statewide determination of BTA using BPJ, establish BTA as reductions in flow and intake velocity, at a minimum, to a level commensurate with that which can be attained by a closed cycle cooling system (Track I). The closed cycle cooling system could be either a wet or dry cooling system. If Track I is not feasible, the power plant must reduce the level of adverse environmental impacts from the cooling water intake structure to a comparable level to that which would be achieved under Track I, using operational or structural controls, or both (Track II); or

1.b. Establish BTA consistent with Alternative 1.a., except that, under this alternative, BTA for power plants that re-power would consist of reductions in flow and intake velocity to levels that are, at a minimum, commensurate with that which can be attained by a closed cycle dry cooling system (Track I). BTA for power plants that retrofit, but do not re-power, would consist of reductions in flow and intake velocity to levels that are, at a minimum, commensurate with that which can be attained by a closed cycle wet cooling system (Track I). Track II would be same as in Alternative 1.a.

2. Establish BTA, based on a statewide determination of BTA, using BPJ for existing power plants, that consists only of Track I, as defined in Alternative 1.a.; or

3. Allow each Regional Water Board to separately employ BPJ to determine BTA on a plant-specific and permit-specific basis.

Discussion:

Alternative 1.a.

Based on a statewide determination of BTA using BPJ for existing power plants, BTA would be established as reductions in flow and intake velocity, at a minimum, to a level commensurate with that which can be attained by a closed cycle cooling system (Track I). In this alternative BTA for minimizing the intake and mortality of all forms of marine life would be either a closed cycle wet (evaporative) cooling system or a closed cycle dry (air cooled) cooling system. The power plant owner or operator would have the flexibility to select either wet or dry closed cycle cooling under Track I. In addition, technological controls that achieve reductions in impacts to those comparable to closed cycle wet cooling would be allowed (Track II).

A recent analysis by Tetra Tech for the Ocean Protection Council (February 2008) states that retrofitting to closed cycle wet cooling is feasible at 12 out of 15 coastal power plants assessed. Twelve plants where wet cooling towers (retrofits) were considered technically and logistically feasible by Tetra Tech were: Alamitos, Contra Costa, Diablo Canyon, Harbor, Haynes, Huntington Beach, Mandalay, Morro Bay, Moss landing, Pittsburg, San Onofre (SONGS), and Scattergood. The three plants where wet cooling towers (retrofits) were considered technically and logistically infeasible by Tetra Tech were Redondo, Ormond Beach, and El Segundo.

At the two nuclear facilities, Diablo Canyon and San Onofre—retrofitting is problematic (although not infeasible). At Diablo Canyon, the constraints of the existing site and the disruption a wet cooling tower retrofit would cause will be problematic. At San Onofre, the installation and operation of wet cooling towers would require additional regulatory approval because of a potential effect on sensitive plant species and environmentally sensitive habitats. It is likely that retrofitting with closed cycle cooling may take more time to address at these plants as compared to fossil fuel plants.

Tetra Tech did not assess the Potrero plant; it may shut down at some point in the near future, pending the outcome of the San Francisco grid reliability study. Tetra Tech did not assess the South Bay Plant since it had been pursuing an air-cooled re-powering project (since that time the application for re-powering has been withdrawn). Hunter's Point has ceased operations and was also not assessed.

Retrofitting to wet cooling towers is not feasible at Redondo Beach because of its immediate proximity to office buildings and residential areas. Compliance with local use requirements would be unlikely. For two other load following facilities – El Segundo and

Ormond Beach – the preferred option could not be configured to meet the minimum site constraints. At both locations, interference from a wet cooling tower's visible plume with nearby flight operations made it probable that plume-abated towers would be required. An acceptable configuration could not be designed for either location due to limited space availability and potential interference with other major structures. In addition, at El Segundo, the cooling towers would be located immediately adjacent to the beach, which may conflict with the requirements the California Coastal Act to protect visual resources. At Ormond Beach, the proximity to the Mugu Naval Air Station suggests the need for plume-abated towers, but sufficient land is not available for this type of tower.

In addition, four existing facilities, El Segundo (partial plant), Encina (Carlsbad Energy Center), Long Beach, and Humboldt Bay, have adopted closed cycle dry cooling as part of their re-powering applications. Therefore, it is clear that some plant operators consider closed cycle dry cooling feasible and economical when re-powering.

Under this alternative, Track I controls would be required if feasible for a particular plant. Feasible would be defined as capable of being accomplished in a successful manner by the final compliance dates in the Policy, taking into account the following site-specific factors: availability of adequate space, potential impacts from increased noise on neighboring commercial or recreational land uses, air traffic safety, public safety, and the ability to obtain necessary permits, such as permits from the California Coastal Commission or local air district.

For Redondo and Ormond Beach, if re-powering using closed cycle cooling is not employed, Track II controls would be necessary. For El Segundo, a combination of re-powering (see below) and Track II controls would be necessary. Track II controls could include replacement of OTC water with recycled treated wastewater, and/or one or more of the technologies discussed above in the Section titled I/E Control Technologies Associated with OTC.

Under this alternative, a reduction in environmental impacts under Track II would be considered to achieve a "comparable level" if both impingement mortality and entrainment of all life stages of marine life are reduced to 90 percent or greater of the reduction that would be achieved under Track 1, using closed cycle wet cooling.

Alternative 1.b.

Under Alternative 1.a. above BTA would be established for existing power plants based on either wet or dry closed cycle cooling and the power plant owner or operator would have the flexibility to select one of those two types of closed cycle cooling under Track I. Alternative 1.b. would establish different requirements for Track I, depending on whether the power plant is re-powering or retrofitting. For retrofits, BTA would be closed cycle wet cooling. For re-powers BTA would be closed cycle dry cooling. Track II would remain the same as under Alternative 1.a.

When retrofitting an existing plant the same power generating system is used and only the cooling system is replaced. In such cases air cooled systems have a high energy penalty resulting in much greater combustion air pollution (including greenhouse gases) per MW of energy produced. Evaporative cooling towers produce particulate emissions (salt drift), but technology does exist to partially mitigate the particulates from cooling towers. The combustion air emissions associated with using evaporative cooling towers are much lower per MW of energy produced than for dry cooling. Based on these relative air pollution characteristics, closed cycle wet cooling would be BTA for retrofits.

When re-powering, the electrical generating systems are replaced with newer, more efficient systems, such as combined cycle technology. In general, power plants that have chosen to re-power have selected closed cycle dry cooling systems. When re-powering with efficient combined cycle generating technology and dry cooling, there are fewer air emissions per MW of electricity produced. Such air-cooled systems are preferable for re-powered plants because particulate air emissions are not associated with the cooling system. In addition, water usage in dry cooling systems is much lower than for evaporative cooling towers; there would be no need for the intake of cooling tower makeup and there would be no cooling tower blowdown discharges. Based on this information, closed cycle dry cooling would be BTA for re-powers.

Alternative 2

This alternative would establish closed cycle cooling as BTA (Track I), but not allow alternative technological controls (Track II) to be used at existing power plants. Under this alternative, the few plants that may not be able to install either wet or dry closed cycle cooling systems may be forced to shut down. Therefore, a policy that does not allow a second track for compliance may be considered unreasonable. This approach is not recommended.

Alternative 3

Allowing the use of BPJ by the Regional Water Boards on a facility- and permit-specific basis will likely result in inconsistency from region to region. This option may also result in a multitude of petitions to the State Water Board for review. This approach will not provide certainty to the operators (or the State energy agencies) and will seriously lengthen the period during which controls are not implemented to protect marine and estuarine life. The permit-specific BPJ approach is not recommended.

Staff recommendation:

Staff recommends Alternative 1.a. Establish requirements for BTA, based on a statewide determination using BPJ, that consist of reductions in flow and intake velocity, at a minimum, to a level commensurate with that which can be attained by closed cycle, wet or dry cooling (Track I). If Track I is not feasible, the power plant must reduce the level of adverse environmental impacts from the cooling water intake structure to a comparable level to that which would be achieved under Track I with closed cycle wet cooling, using operational or structural controls, or both (Track II).

Makeup Water for Closed Cycle Wet Cooling

Closed cycle evaporative cooling systems, more often referred to as wet cooling towers, function by transferring waste heat to the surrounding air through the evaporation of water, thus enabling the reuse of a smaller volume of water several times to achieve the desired cooling effect. Compared to a once-through cooling system, wet cooling towers may reduce the volume of water withdrawn from a particular source by as much as 93-96 percent depending on various site-specific characteristics and design specifications.

In their study titled, *California Coastal Power Plants: Cost and Engineering Analysis of Cooling System Retrofits*, Tetra Tech estimates the design make up water required for retrofitted cooling towers at thirteen of the State's OTC power plants. Table 11 summarizes the Tetra Tech estimated makeup water requirements for wet cooling tower retrofitted power plants compared with design OTC water requirements.

Table 11. Makeup Water Requirements for Wet Cooling Tower Retrofitted Power Plants Compared with OTC Water Requirements

Plant	Combined OTC Design Intake Volume (mgd)	Combined Cooling Tower Makeup Volume (mgd)	%Reduction
Alamitos	1152	57	95
Huntington	484	26	95
Haynes	858	36	95-96
Harbor	81	4.6	94
El Segundo	379	20	95
Diablo Canyon	2484	108	96
Contra Costa	431	20	95
Moss Landing	1166	56	95
Mandalay	241	13	95
Pittsburg	462	20	96
Ormond Beach	654	47	93
SONGS	2287	110	95
Scattergood	495	23	95

The re-use of treated wastewater may have a potential application as makeup water for alternative cooling by evaporative cooling towers. The reduced volume requirements of a cooling tower system may make wastewater effluent more feasible. This would be especially true in the situations where the sewage plant is in close proximity and costs of a pipeline are not exorbitant. In such cases, the wastewater would need to be of sufficient quality (in accordance with requirements in Title 22 of the California Code of Regulations) to ensure plant safety and prevent aerial contamination. Any concentrated chemical constituents or solids would likely need to be disposed at permitted land disposal sites.

Alternatives:

1. Do not specify source water preferences in the Policy.

2. Require that power plant owners consider the feasibility of using recycled wastewater for power plant cooling.

Discussion:

Alternative 1: This alternative is inconsistent with the State Water Board's policy direction regarding the use of recycled wastewater. The State Water Board's 1975 "Water Quality Control Policy on the Use and Disposal of Inland Waters Used for Powerplant Cooling" establishes recycled wastewater being discharged to the ocean as the highest priority for power plant cooling source water. Further, the State Water Board is committed to encouraging the safe use of recycled wastewater in order to conserve the state's scarce potable water resources. To that end, the State Water Board is currently working on development of a recycled water policy.

Alternative 2: For the reasons explained above, this alternative is consistent with the State Water Board's policy direction to favor the safe use of recycled wastewater.

Staff recommendation:

Staff recommends Alternative 2: Require that power plant owners consider the feasibility of using recycled wastewater for power plant cooling.

Nuclear and Conventional Facilities

In the Phase II rule, USEPA included a provision that authorized a site-specific compliance alternative for nuclear facilities to address safety concerns unique to these facilities. This provision stated that if a nuclear facility "demonstrate[s] to the Director based on consultation with the Nuclear Regulatory Commission that compliance with [subpart J] would result in a conflict with a safety requirement established by the Commission, the Director must make a site-specific determination of BTA for minimizing adverse environmental impact that would not result in a conflict with the Nuclear Energy Commission's safety requirement."[zz]

In *Riverkeeper II,* the court rejected industry's challenge to the Phase II rule on the ground that USEPA had failed to consider the unique safety concerns relating to nuclear facilities. Industry representatives had argued that nuclear facilities face unique safety concerns associated with the stable flow of cooling water to ensure safe reactor operation and shutdown. They contended that any change in water intake or obstruction

[zz] 40 C.F.R. §125.94(f).

of water intake systems due to, for example, the clogging of screens, could affect nuclear power facilities in specific and serious ways. The court concluded, however, that the site-specific compliance alternative cited above adequately addressed industry's concerns.

Alternatives:

1. Grant nuclear facilities an exemption from the Policy.

2. Do not exempt nuclear facilities from the Policy, but allow them a longer time to comply than conventional facilities and include a safety provision to assure that the Policy's requirements do not compromise safety.

3. Regulate nuclear and conventional facilities in the same manner.

Discussion:

Alternative 1: Under design flow conditions, the State's nuclear facilities can withdraw up to 4.8 billion gallons of cooling water per day. In comparison, the combined average cooling water intake flow for all the State's OTC plants in 2005 was 9.4 billion gallons per day (this does not include flows for Humboldt Bay, Hunters Point, and Long Beach power plants). Nuclear power plants can impinge and entrain substantial numbers of aquatic organisms because of the large volume of cooling water flows that pass through these facilities each day. Granting nuclear facilities an exemption from the Policy would allow considerable impingement and entrainment impacts to continue uncontrolled. This is not recommended.

Alternative 2: This alternative would give nuclear facilities more time to comply with the Policy's requirements because of safety concerns. It would also alleviate concerns that the Policy would impose requirements that would compromise the safety at a nuclear power plant. Since this alternative requires eventual compliance with the Policy, impingement and entrainment would also be controlled.

Alternative 3: This alternative would require that nuclear facilities meet the same time schedule and controls as conventional facilities. While this alternative requires all facilities to control impingement and entrainment, it does not address possible safety concerns and the large scale facility changes that nuclear facilities may face. This is not recommended.

Staff recommendation:

Staff recommends Alternative 2: Allow nuclear facilities more time to comply with the Policy's requirements.

Compliance Schedule

Planning, permitting and retrofit installation of BTA will take considerable time and resources to accomplish. There may be significant down time during which power will not be generated from the affected units.

Alternatives:

1. Regional Water Board staff may schedule BTA retrofits on a case-by-case basis.
2. State Water Board staff may establish a power plant specific schedule in a statewide policy.
3. The statewide policy may provide deadlines for BTA retrofits for different classes of power plants, and scheduling retrofits within those deadline periods would be accomplished in collaboration with State energy agencies.

Discussion:

The general consensus of the energy industry is that about 5 years are needed to plan, site, permit, and construct a new major power plant. Permitting alone for retrofits may take one year or more, with the larger capacity factor and nuclear plants requiring more time to plan and permit. If plant operators opt to re-power, the permitting may be considerably more extensive.

For retrofits, following construction of the closed cycle cooling system, the installation phase (connecting the new cooling system to the generation system) may require the plants to be down for a significant period of time. For installation, fossil fueled plants will likely be off the grid for four weeks or more, and nuclear-fueled power plants may take up to six months or more. According to the Grid Reliability Study (Jones and Stokes, 2008), the State's electrical supply can be maintained throughout the retrofit period, but each plant will require time to plan and permit the alternative cooling systems.

Grid reliability is an issue of statewide concern. To promote grid reliability it is not advisable to assume that all plants can convert to BTA at the same time in a very short time frame. Conversion to BTA must be accomplished in an orderly and coordinated fashion.

The mission of the Water Boards is to protect water resources and marine/estuarine life. The Water Boards are experts in protecting water resources but are not energy experts. If Regional Water Boards individually attempt to schedule retrofit or re-power projects associated with NPDES permits, there may be disruptions in grid reliability. Likewise, if the State Water Board attempts on its own to set a schedule, disruptions to the grid may occur. From a grid reliability standpoint, the safest approach would be for the Water Boards to collaborate with the experts in the State's energy and coastal permitting agencies.

Staff recommendation:

Staff recommends Alternative 3. The State Water Board will convene a Statewide Task Force, which will include agencies with oversight in energy resource planning and permitting. This Task Force will assist in reviewing and implementing scheduled conversions to BTA by existing power plants.

Monitoring Provisions to Assess Track II Reductions in I/E

Existing power plant dischargers opting to use Track II for compliance with the Policy would need to reduce I/E impacts through operational or technological controls. How should these reductions be quantified?

Alternatives:

1. Do not require further monitoring; only estimate I/E reductions based on reductions in flows.
2. Do not include specific monitoring language in the Policy; Regional Water Board staff would have to independently develop monitoring language for permits.
3. Include consistent Track II monitoring language to be used statewide.

Discussion:

According to the Tetra Tech report wet-cooling towers would result in a control of 93-96% water consumption (flow) depending on the plant, if ambient marine or brackish water is used. Track II controls must be comparable to Track I.

In some cases, simply comparing flows before and after controls may be the simplest (but somewhat inaccurate) way to estimate I/E reductions. Some Track II measures may actually involve a reduction in flow, such as replacement of OTC water with treated wastewater or the use of variable frequency drive pumps. In such cases, intake flow reductions may be related to entrainment reductions. If Track II results in flow reductions to levels comparable to Track I, I/E reductions may be similar (but possibly not identical) to flow reductions. There may not be an exact relationship between water reduction and entrainment reduction.

If Track II plants employ screen technologies (e.g., wedgewire screens) to reduce entrainment, there will not be a reduction in flow, just a reduction in entrainment. In other cases, especially when a mix of Track II controls are employed, I/E monitoring would be necessary. In order to fully understand the reductions in I/E, pre- and post-control monitoring data would be required. Possibly the studies performed under the PIC and CDS requirements of the suspended USEPA Phase II rules may suffice for the pre-control I/E. In such cases only post-control monitoring would be needed. However, in cases when a particular PIC/CDS study may be deficient in some way, then both pre- and post- control monitoring may be necessary for a Track II plant.

If Regional Water Boards independently determine the monitoring requirements, there may be inconsistencies statewide. One consistent statewide approach would be preferable, and would also provide guidance for permit writers in requiring a monitoring plan.

Staff recommendation:

Staff recommends Alternative 3: Include consistent Track II monitoring language to be used statewide.

Interim Requirements

Considering that there will likely be a significant time lag between the adoption of the policy and ultimate retrofit to BTA, impacts to marine life will continue for that interim period.

Alternatives:

1. Provide no interim measures in a statewide policy.
2. Provide interim measures for impingement of large organisms only.
3. Provide interim measures for entrainment when power is not generated only.
4. Provide restoration as an interim measure for I/E.
5. Provide all of the above interim measures, including large organisms exclusion devices, reduction in entrainment when power is not generated, and restoration for the remaining interim I/E impacts.

Discussion:

The National Marine Fisheries Service reported to staff that large organisms such as marine mammals and sea turtles are regularly impinged in offshore intakes. Such impacts to protected marine life should be addressed more rapidly than by waiting for a full BTA retrofit at power plants. Existing power plants with offshore intakes can reduce impingement of large organisms by installing large organism exclusion devices having a mesh size no greater than 4” square.

Another impact that may be addressed on a short-term basis prior to full BTA retrofit is impingement and entrainment of marine life during periods when no energy is being produced. Typically, OTC water flows continue when electrical generation is not needed in order to prevent biofouling. In addition, in-plant waste streams, including in some cases treated sewage, are commingled and disposed of in OTC discharges.

Flow should be reduced to ten percent of the average daily flow during periods when electrical energy is not being produced for a period of two or more consecutive days. Flow reduction will reliably reduce both Impingement and entrainment impacts of OTC.

There are a variety of options to reduce intake flows including re-powering to combined cycle combustion technology, seasonal outages, and variable speed pumps. An example of flow reduction is at the Contra Costa Power Plant, which currently employs variable speed pumps and seasonal reductions to avoid entrainment of striped bass larvae. The CEC discussed these intake flow reduction options in Chapter 6 of its June 28, 2005 report.

Not requiring interim measures would allow the I/E impacts to continue unabated until the dates of ultimate compliance. Ultimate compliance, i.e. BTA installed, may not be accomplished for several years due to the lengthy planning, permitting and construction timelines. The interim measures proposed would at least offset the impacts during the interim prior to installation of BTA.

Restoration as an Interim Measure

In the past, USEPA and the states have allowed existing power plants to comply with §316(b), in part, by using restoration measures to address impingement and entrainment losses. California law on intakes using seawater for cooling at new and expanded power plants specifically references the use of best available mitigation measures feasible, as well as the best available site, location, and technology feasible, to minimize intake and mortality of marine life.

The original USEPA Phase I rule for new power plants allowed owners or operators to comply with the rule by using restoration measures to compensate for ecosystem losses due to impingement and entrainment. In *RiverKeeper I*, the Second Circuit Court of Appeals ruled that USEPA exceeded its authority because “restoration measures are inconsistent with Congress’ intent that the ‘design’ of intake structures be regulated directly, based on the best technology available . . .” (358 F.3d at 190). In *RiverKeeper II*, the Second Circuit Court of Appeals reached the same conclusion for existing power plants. The court once again decided that under CWA Section 316(b) restoration measures, such as restoring habitat or restocking fish, could not be considered BTA.

It is clear that restoration to comply with CWA 316(b) is not BTA. Restoration of habitat, however, is valuable and should be encouraged as an offset during the interim until BTA is fully complied with. Determination of restoration funding may be determined in one of two ways: a) by simply basing restoration on plant flow rates; or b) by a more rigorous biological model such as habitat production foregone.

Habitat production foregone is one of the most promising methodologies for use in assessing entrainment losses and then applying that information to a restoration project. This methodology estimates the amount of habitat (production foregone) it would take to produce the organisms lost to entrainment. Estimates of lost production can be for affected individuals only or the affected individuals plus the production of progeny that were not produced. This method can address all losses across all habitat types.

Habitat production foregone requires an estimate of the Proportional Mortality (i.e., the proportion of larvae killed from entrainment to the larvae in the source population). An estimate is also required of the source water body area for the target species' source population. The product of the average Proportional Mortality and the source water body area is an estimate of habitat production foregone area that is lost to all entrained species. This habitat area can then be restored in a nearby area. For example, if the average Proportional Mortality of estuarine species is 17 percent and the area of the source water estuary is 2000 acres, then the habitat production foregone is equal to (17% x 2000 acres) = 340 acres.

Restoration costs will necessarily be site-specific. Placing a dollar amount on ecological effects or societal values can be controversial. Use of the Habitat Production Foregone methodology is advantageous because the cost of restoring, enhancing, or protecting a specific amount of habitat (340 acres in the above example) can be readily estimated. Power plants that utilize restoration measures must demonstrate the efficacy of the restoration measures to the Regional Water Board.

Staff recommendation:

Staff recommends Alternative 5: Provide interim measures, including large organism exclusion devices, reduction in entrainment when power is not generated, and restoration for the remaining interim I/E impacts.

Summary of Staff Recommendations and Proposed Policy

The staff recommendation is to moving forward with a statewide policy to provide statewide consistency in implementing CWA Section 316(b) and California Water Code Section 13142.5(b). The draft policy would apply to existing power plants, defined as any power plant that is not a new power plant. New power plants would be any plant that is a new facility, as defined in 40 C.F.R. §125.83, that is subject to Subpart I, Part 25 of the Code of Federal Regulations.

The draft policy would set BTA (Track 1) as closed cycle cooling for existing power plants. For those plants where it is not feasible for closed cycle cooling to entirely replace once-through cooling, the draft policy would allow other types of technological retrofits or operational measures that would constitute Track II controls. Track II must be comparable to Track I. For the few plants that might employ Track II, the policy would specify monitoring provisions to quantify I/E reductions.

With regard to makeup water for Track I, the policy would encourage the use of recycled water for cooling water in lieu of ambient marine and estuarine waters whenever feasible, but would not reiterate the specific source water preferences from the 1975 Board Policy.

The statewide policy may provide deadlines for BTA retrofits for different classes of power plants, and scheduling retrofits within those deadline periods would be accomplished in collaboration with State energy agencies. As part of that compliance schedule, nuclear facilities would be allowed more time to comply with the Policy's requirements.

The draft policy would require interim measures to eliminate impingement of large organisms at offshore intakes, and reducing flows when power is not generated. Restoration would be required only as an interim measure.

The proposed draft Policy is provided in Appendix A.

PUBLIC PROCESS AND SCHEDULE

This scoping document and the attached draft policy are the first step in a public process. The State Water Board will hold a scoping meeting. Following the scoping meeting, the State Water Board will consider comments in modifying the draft policy and preparing a substitute environmental document. Under its certified regulatory program, the State Water Board prepares a substitute environmental document that addresses potential environmental impacts, alternatives, and mitigation measures. A public hearing will be held. Staff will then formally respond to comments received at that public hearing step. The following is a tentative schedule.

Table 12. Tentative Schedule for Adoption of Proposed Policy

Activity	Tentative Dates (2008)
Release scoping document with preliminary draft policy	March
Expert Review Panel Findings	April/May
Public scoping workshop/public comments	May
Release Draft Policy and Substitute. Env. Document	July
Public Hearing	September
Response to Comments/Final Draft Document & Policy	October/November
State Water Board Meeting to adopt Policy	December

SCIENTIFIC REVIEW

Expert Review Panel

At its April 20, 2006 meeting, the OPC adopted a "Resolution of the California Ocean Protection Council Regarding the Use of Once-Through Cooling Technologies in Coastal Waters." In that resolution, the OPC resolved "to encourage the State Water Resources Control Board's formation of a technical review group to ensure the required technical expertise is available to review each power plant's data collection proposals, analyses and impact reductions, and fairly implement statewide data collection standards needed to comply with § 316(b)."

Thermal, impingement, and especially entrainment impacts from OTC are often difficult to accurately define. For example an analysis of entrainment impacts, controls, and mitigation measures requires very specialized technical expertise in certain areas of physical oceanographic processes, coastal marine biology, ecological modeling, restoration ecology, and engineering.

The State Water Board has contracted with Moss Landing Marine Laboratory to convene an Expert Review Panel (ERP) to review this document and the proposed policy. The ERP includes membership from academic and consulting scientists and technical experts representing industry and the environmental community. Staff, in conjunction with the ERP, developed a set of questions relative to the draft policy. These initial questions that will be addressed by the ERP are as follows:

1. How will baseline be defined?

   Note: Under the California Environmental Quality Act, the baseline for this project is the current condition of the coastal and estuarine OTC plants. However, in the application of certain aspects of the draft policy, i.e. Track II and interim restoration, how should existing controls be considered?

   In determining Track II controls (when applicable) should environmental impacts be assessed retrospectively, i.e., before existing site-specific controls were in place? Or should impacts be assessed under current operating conditions, i.e., taking into account existing controls? Likewise, for determining interim restoration levels, should credit be given for existing site-specific controls or restoration projects?

2. Has the State Water Board staff correctly estimated statewide marine life due to uncontrolled once-through cooling?

3. How will trophic and ecosystem effects be quantified? Using models?

4. Are the interim controls effective and feasible to prevent mortality and to reduce takes of wildlife?

5. For Track I, did staff adequately consider adverse impacts associated with conversion to closed-cycle cooling?

6. For Track II, are the proposed monitoring requirements appropriate to determine actual percent reductions in mortality?

7. What data and models should be required to determine restoration offsets?

8. How should restoration projects be monitored to determine compliance?

9. Will the policy requirements be implemented using a transparent process?

Additional questions may also be posed to the ERP. Staff will consider the input from the ERP before it releases the next draft policy and substitute environmental document.

External Scientific Peer Review

In 1997, section 57004 was added to the California Health and Safety Code (Senate Bill 1320-Sher) which requires an external scientific peer review of the scientific basis for any rule proposed by any board, office, or department within California Environmental Protection Agency (Cal/EPA). Scientific peer review helps strengthen regulatory activities, establishes credibility with stakeholders, and ensures that public resources are managed effectively. After the draft policy and substitute environmental policy are released, State Water Board staff will obtain an external scientific review.

CALIFORNIA ENVIRONMENTAL QUALITY ACT

Introduction

The State Water Board is the lead agency for this project under the California Environmental Quality Act, or CEQA (Public Resources Code, §21000 *et seq.*) and is responsible for preparing environmental documentation for the proposed Policy. The California Secretary of Resources has certified the Water Boards' water quality planning process as exempt from certain CEQA requirements. These include the requirements to prepare Environmental Impact Reports (EIRs), Negative Declarations, and Initial Studies (Cal. Code Regs, tit. 14, §15251(g); see Public Resources Code, §21080.5.). Instead, the State Water Board must fulfill the requirements of its "certified regulatory program" regulations when adopting plans, policies, and guidelines. Under these regulations, the State Water Board must prepare a written report that describes the proposed project, analyzes reasonable alternatives, and identifies mitigation measures to minimize any significant adverse environmental impacts of the proposed activity. (Cal. Code Regs., tit. 23, §3777.)

In addition, CEQA imposes specific obligations on the Water Boards when they adopt rules or regulations establishing performance standards or treatment requirements. Public Resources Code §21159 requires that the Water Boards concurrently perform an environmental analysis of the reasonably foreseeable methods of compliance. The environmental analysis must address the reasonably foreseeable environmental impacts of the methods of compliance and reasonably foreseeable alternatives and mitigation measures.

Public Resources Code §21159 does not require the State Water Board to prepare a "project level analysis". Rather, the State Water Board must prepare a program-level analysis, i.e. a Tier 1 analysis, that takes into account a reasonable range of environmental, economic, and technical factors, population and geographic areas, and specific sites. Site-specific or project-level impacts will be considered by the appropriate public agency that is ultimately responsible for approving or implementing individual projects.

Environmental Resources

Under its certified regulatory program, the State Water Board will prepare a substitute environmental document that addresses potential environmental impacts, alternatives and mitigation measures. Resource areas that could be affected are briefly discussed below.

Aesthetics

Cessation of once-through cooling for power production and retrofitting of existing plants with wet cooling towers could adversely affect aesthetics depending on local conditions and applicable laws, ordinances, regulations, and standards. Impacts could result from the wet cooling towers themselves, and/or the plume created by conventional wet cooling towers. Plume-abated towers are generally 15 to 30 feet taller than conventional wet cooling towers and could have a greater impact on visual resources than conventional towers.

Agricultural Resources

Agricultural land is not expected to be impacted by the construction of cooling towers at any of the existing once-through-cooling power plants (Tetra Tech 2008).

Air Quality

The California Air Resources Control Board (CARB) has estimated potential Policy induced increased air emissions from two types of hypothetical power plants, a 300 MW steam turbine power plant unit and a 540 MW combined-cycle power plant unit, both fueled by natural gas[aaa]. CARB's findings are incorporated into this document as the Air Quality impacts section:

Retrofitting power plants from OTC to wet or dry cooling will cause decreases in net plant efficiency and increases in auxiliary power consumption; thereby, resulting in decreases of energy production and distribution. To make up for the energy loss, fuel consumption would need to be increased to produce an equivalent amount of electricity. This would result in increased emissions from the combustion of additional fuel. This analysis will quantify criteria pollutants [e.g. total organic gases (TOG), reactive organic gases (ROG), oxides of nitrogen (NOX), oxides of sulfur (SOX), carbon monoxide (CO), particulate matter of 2.5 microns or less (PM2.5)] and carbon dioxide (CO2) emissions produced by the combustion of additional fuel.

A second source of increased air emissions is from evaporation and drift produced by wet cooling towers. Wet cooling towers transfer heat from recirculated water to air

[aaa] California Air Resources Control Board, 6/1/07 memo to State Water Board.

traveling out of the tower. This heat transfer from water to air increases the temperature of the air and increases the air's humidity to 100 percent. As water vapor leaves the cooling tower, droplets of make-up water called drift are entrained along with the water vapor. Drift carries the same pollutants found in the tower's make-up water. These pollutants may include, but are not limited to PM, bacteria and pathogens, salts and minerals, volatile organic compounds (VOCs), and chemical compounds. This analysis will quantify the PM and PM10 emissions from wet cooling towers and discuss the impacts caused by wet cooling tower pollutants.

Energy Penalties

A retrofitted power plant with wet or dry towers will produce less energy than it did with OTC while burning the same amount of fuel. This difference in energy production is called an energy penalty and is often represented as a percentage. Currently, there are no energy penalty studies specific to retrofitting California coastal power plants from OTC to wet or dry cooling towers. Therefore, the energy penalties used in this analysis will be national averages reported by the USEPA and are summarized in Table 13.

Table 13. National Average, Mean-Annual Energy Penalty, Summary Table

Cooling Type	Percent Maximum Load	Mean-Annual Nuclear Percent of Plant Output	Mean-Annual Combined-Cycle Percent of Plant Output	Mean-Annual Fossil-Fuel Percent of Plant Output
Wet Tower vs. Once-Through	67	1.7	0.4	1.7
Dry Tower vs. Once-Through	67	8.5	2.1	8.6

Emissions from Increased Fuel Combustion

Retrofitting power plants from OTC to wet or dry cooling towers will cause decreases in turbine efficiency, increases in fan energy requirements, and increases in pumping energy requirements. As a result, power plants will see reductions in the amount of net energy for export to the grid. Retrofitted power plants have three options to address their energy reduction concerns: 1) purchase power from the grid to make up for lost power; 2) burn additional fuel on-site to replace lost power; or 3) do nothing to replace lost power.

According to the USEPA, it is more likely that power plants that do not operate at full capacity on an annual basis will burn additional fuel to make-up for their energy loss. Nuclear power plants currently operate at or near capacity limits and those plants may have to purchase power from the grid. An indirect increase in emissions would result from purchasing power from the grid due to an increase in fuel combustion where additional electricity is produced.

The combustion of additional fuel to make up for lost power will result in criteria pollutant and CO2 emission increases. CARB staff does not have information to determine the type of cooling systems California OTC power plants would utilize. Therefore, CARB staff estimated emissions from two types of hypothetical power plants, a 300 MW steam turbine power plant unit and a 540 MW combined-cycle power plant unit, both fueled by natural gas. Table 7 (above) shows the baseline emissions inventory for the hypothetical 300 MW steam turbine power plant unit and the hypothetical 540 MW combined-cycle power plant unit cooled by OTC. Tables 14 and 15 show potential air emission increases caused by wet or dry cooling tower retrofits for those same plants.

Table 14. Increase of Emissions from Additional Fuel Consumption – Wet Cooling

Unit	Greenhouse Gas	Criteria Pollutants					
	CO_2	TOG	ROG	NOX	SOX	CO	$PM_{2.5}$
Steam Turbine (tons/yr)	4,067	0.32	0.14	0.91	0.03	2.60	0.29
Steam Turbine %Increase	1.7	1.8	1.8	1.7	1.6	1.7	1.7
Combined Cycle (tons/yr)	3,173	0.25	0.11	0.71	0.02	2.03	0.22
Combined Cycle %Increase	0.40	0.41	0.42	0.40	0.32	0.40	0.39

Table 15. Increase of Emissions from Additional Fuel Consumption – Dry Cooling

Unit	Greenhouse Gas	Criteria Pollutants					
	CO_2	TOG	ROG	NOX	SOX	CO	$PM_{2.5}$
Steam Turbine (tons/yr)	22,130	1.71	0.74	4.94	0.17	14.14	1.56
Steam Turbine %Increase	9.4	9.4	9.4	9.4	9.2	9.4	9.4
Combined Cycle (tons/yr)	16,949	1.31	0.57	3.79	0.13	10.83	1.20

	Greenhouse Gas	**Criteria Pollutants**					
Combined Cycle %Increase	2.1	2.1	2.2	2.1	2.1	2.1	2.1

Emissions from Wet Cooling Towers

Wet cooling towers are designed to cool by evaporation. Through this process droplets of water called drift may be entrained out of the cooling tower along with water vapor. Drift contains the same suspended material, chemical constituents, and bacteria found in the make-up water used for cooling. Therefore, a variety of pollutants may be emitted from wet cooling towers, and their effects and/or concentrations are influenced by many factors including, but not limited to: make-up water used, chemicals used for make-up water treatment, the location of the cooling tower, and site-specific weather (e.g., wind speed, wind direction, temperature, humidity, etc.). The most common emission of concern associated with wet towers is particulate matter less than or equal to 10 microns (PM10) in diameter. Other environmental impacts such as vapor plumes, bacterial and/or pathogenic species, salts, volatile organic compounds (VOCs), and chemical compounds used for treatment may be emitted from wet cooling systems.

Particulate Matter

Wet cooling towers emit solid or liquid (excluding water) material into the atmosphere as PM emissions.

Reisman and Frisbie (2003) have indicated that depending on the droplet size distribution of the drift, only a certain percentage of drift PM is PM10. From their report, cooling towers using make-up water with a total dissolved solids (TDS) concentration near 2,000 parts per million (ppm) will have a PM10 emission rate which is approximately 60% of the calculated PM emission rate, and cooling towers using make-up water with a TDS concentration over 12,000 ppm will have a PM10 emission rate which is 5% of the calculated PM emission rate (at higher TDS values the drift droplets contain more solids and upon evaporation result in more solid particles larger than PM10 for any given initial droplet size).

Using the emission rates suggested by Reisman and Frisbie (2003), PM10 emission estimates are summarized in the far right column of Table 16. These estimates are not intended to represent site-specific retrofit conditions, but illustrate possible values for each factor used in calculating PM10 emissions. A conservatively high PM10 emission rate was also calculated assuming 100% of the calculated PM emission is PM10.

Table 16. Wet Cooling Tower PM10 Emission Estimates*

Water Type	Water Circulation Rate (gpm)	Operating Time (hrs/yr)	TDS of Circulating Water[a] (ppm)	Drift Loss[b] (%)	Density of Water (lbs/gal)	PM Emissions = 100% PM10 (tons/yr)	PM Emissions = 5% and 60% PM10 (tons/yr)
Fresh Water	180,000	2190	1,947	0.002	8.34	3.84	2.30[c]
Reclaimed Water	180,000	2190	2,402	0.002	8.34	4.74	2.84[c]
Produced Water	180,000	2190	34,800	0.002	8.34	68.65	3.43[d]
Agricultural Return Water	180,000	2190	49,891	0.002	8.34	98.41	4.92[d]
Seawater	180,000	2190	55,000	0.002	8.34	108.49	5.42[d]

* PM10 emission = (water circulation rate) x (operating hours) x (total dissolved solids of circulated water) x (drift loss) x (density of water)

a. TDS values for each water type (excluding seawater) were obtained from the 2003 EPRI/CEC report. The seawater TDS value was obtained from the 1995 Marley Cooling Tower Report.
b. Drift loss percentages of .002% were obtained from the 2003 EPRI/CEC report.
c. 60% of the calculated PM emissions are PM10.
d. 5% of the calculated PM emissions are PM10.

Other Air Related Impacts

As hot water vapor exits the wet cooling tower and mixes with cooler ambient air, the water vapor condenses and becomes tiny droplets. These vapor plumes may cause icing and fogging conditions during the cold and damp parts of the year.

Wet cooling towers may provide suitable environments for bacteria and pathogenic species to live and multiply in. Releases of bacteria and/or pathogenic species and their impacts on communities may be a concern. Power plant operators can eliminate or reduce bacteria and pathogen impacts by limiting the amount of dust and airborne debris entering into the tower, using biocides, increasing the velocity of water to decrease settling particles, and enhancing drift eliminators.

Salt deposition from wet cooling towers is caused by salinity of the make-up water and may cause environmental impacts and damage to sensitive equipment located nearby. To reduce this impact, operators can use make-up water that has no or low salinity content and/or maintain the efficiency and effectiveness of the cooling tower's drift eliminators.

Many different types of source waters can be used for power plant cooling. These sources include fresh water, reclaimed water, and degraded water (e.g., sea water, brackish water, contaminated groundwater, and agricultural water). Organic compounds, chemical compounds, minerals, and metals can be found in those sources of water. Power plants operators can minimize possible air emissions of those constituents by using make-up water from sources that do not contain those compounds and/or by maintaining the efficiency and effectiveness of the cooling tower's drift eliminators.

Emissions from Dry Cooling Towers

Dry cooling towers do not cool by evaporation. Instead, fans are used to cool the recirculated make-up water. Therefore, the only source of air emissions from dry cooling towers is the combustion of additional fuel to make up for the parasitic load required to operate the fans and water pumps.

Air District Survey

The 19 coastal OTC power plants are located in the Bay Area Air Quality Management District (BAAQMD), Monterey Bay Unified Air Pollution Control District (MBUAPCD), North Coast Unified Air Quality Management District (NCUAQMD), South Coast Air Quality Management District (SCAQMD), San Diego Air Pollution Control District (SDAPCD), San Luis Obispo Air Pollution Control District (SLOAPCD), and the Ventura Air Pollution Control District (VAPCD).

At the request of the State Water Board, CARB contacted the seven local air districts stated above and asked about required permits and the permitting process. Most local air districts require permits for wet cooling; however the SCAQMD regulations do not currently require permits for evaporative cooling towers unless they emit toxic pollutants. Dry cooling permits are considered on a case-by-case basis. In general, the permitting process timeframe is 30 days to review for an application's completeness, 180 days to grant authorization of construction and from one to seven years to complete construction (depending on the local air district).

Biological Resources

Adoption of a statewide policy for power plant cooling is not expected to cause any adverse biological effects. In contrast, the reduction in aquatic life impingement and entrainment is expected to have a beneficial effect on the biological resources of the near coastal and estuarine environments.

Cultural Resources

The construction of facilities to replace once-through-cooling may affect cultural resources, if present. The environmental review associated with each facility retrofit will need to evaluate the potential impacts the projects may have on cultural resources and develop appropriate mitigation.

Water Quality

Compliance alternatives for OTC power plants that would substantially change the characteristics of wastewater effluent include the installation of cooling towers (wet cooling systems) and dry cooling systems. It is not anticipated that the installation of aquatic barrier nets or fine mesh screening systems would change the characteristics of the effluent discharge.

Dry Cooling Systems

Dry cooling systems are so named because the removal of heat from the steam cycle is accomplished through sensible heat transfer (convection and radiation) rather than through latent heat transfer (evaporation) that is characteristic of wet cooling systems. By relying solely on sensible heat transfer, dry cooling systems eliminate the need for a continuous supply of cooling water to the condenser, thus reducing many of the environmental concerns associated with once through or closed cycle wet cooling systems—such as adverse impact on aquatic ecosystems, consumptive use of water resources, and plume or drift emissions.

Installation of dry cooling systems at power plants would eliminate the need for cooling water, substantially decreasing the wastewater discharge. Dry cooling systems still use water to recirculate between generators and the cooling system, and therefore require a water source and possibly wastewater disposal for that use.

Since dry cooling systems reject heat to the surrounding air instead of the ocean, environmental impacts to surface waters due to heat disposal would be eliminated.

Wet Cooling Systems

Evaporative cooling systems, often referred to as wet cooling towers, function by transferring waste heat to the surrounding air through the evaporation of water, thus enabling the reuse of a smaller volume of water several times to achieve the desired cooling effect. Compared to a once-through cooling system, wet cooling towers may reduce the volume of water withdrawn from a particular source by as much as 96 percent depending on various site-specific characteristics and design specifications.

The volume of makeup water required is the sum of evaporative loss and the blowdown volume required to maintain the circulating water in each towers at the design TDS (total dissolved solids) concentration. Drift expelled from the towers represents an insignificant volume by comparison and is accounted for by rounding up estimates of evaporative losses. Makeup water volumes are based on design conditions, and may fluctuate seasonally depending on climate conditions and facility operations.

Since cooling towers reduce the volume of cooling water needed, the impingement and entrainment losses will be reduced. Also, thermal impacts to the receiving water will be greatly reduced because much of the condenser's heat would be rejected to the atmosphere (evaporated cooling water) instead of the receiving water body. However, concentration of chemical additives and existing pollutants in the makeup water is a concern. Where OTC water is typically similar in chemical pollutant characteristics to the receiving water with the addition of low volume plant wastes and chemical additives, cooling towers will concentrate pollutants from low volume plant waste streams, make-up water, and additives.

Table 17 provides a summary of effluent data for two cooling towers operating between six and eight cycles of concentration. Makeup water for these cooling towers is partially treated Contra Costa canal water for Cooling Tower 1 and potable water for Cooling Tower 2.

Table 17. Effluent Data for Cooling Towers Operating at 6-8 Cycles of Concentration with Potable Water Makeup

Parameter	Units	Data Set Size (n)	Percent Non-detect	Max Detected Value	Mean
		Cooling Tower 1			
pH	unit	1884	0	8.6	7.44
Temp	F	1884	0	86	71.56
As	µg/l	26	4	30	7.69
Cr(VI)	µg/l	10	90	1	1.85
Cu	µg/l	80	0	30	20.19
Pb	µg/l	62	32	4.6	0.59
Hg	µg/l	79	3	0.05	0.01
Ni	µg/l	88	0	73.2	14.57
Se	µg/l	48	10	48.6	5.79
Ag	µg/l	35	94	0.1	0.21
Zn	µg/l	78	1	100	32.04
CN	µg/l	48	77	7.5	2.30
TCDD01	pg/L	3	33	0.38	0.29
Cr	µg/l	37	3	119	9.07
Phenanthrene	µg/l	4	75	0.07	0.03
Bromoform	µg/l	4	0	3.3	2.03
		Cooling Tower 2			
Parameter	**Units**	**Data Set Size (n)**	**Percent Non-detect**	**Max Detected Value**	**Mean**
pH	unit	1903	0	8.6	7.73
Temp	F	1903	0	86	73.42
Cr(VI)	µg/l	10	60	5.6	2.42
Cu	µg/l	87	0	33	20.14
Pb	µg/l	63	3	34	3.53
Hg	µg/l	76	1	0.05	0.02
Ni	µg/l	73	1	92.9	10.15
Se	µg/l	26	15	5	2.08
Zn	µg/l	80	0	390	75.67
CN	µg/l	46	78	5	2.12
TCDD01	pg/L	4	50	0.07	0.26
Cr	µg/l	29	3	127	9.34

Tetra Tech's 2007 draft of their Alternative Cooling System Analysis summarizes possible NPDES permitting issues that each specific facility would likely face when converting from OTC to wet cooling. Since NPDES permit limits are established to protect receiving waters from toxic conditions, a facility's ability to comply with limits associated with retrofit wet towers is a direct measure of possible impacts to water quality. The Tetra Tech draft permitting/water quality findings for each facility are summarized below.

Individual Power Plant Reviews, Cooling Towers and Water Discharges

Alamitos Generating Station

At maximum operation, wet cooling towers at Alamitos Generating Station (AGS) will result in an effluent discharge of approximately 38 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, treated sanitary waste, and cleaning wastes. These low volume wastes may add an additional 3.5 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, AGS will be required to modify its existing individual wastewater discharge (NPDES) permit. Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0001139, as implemented by Los Angeles Regional Water Board Order 00-082. All wastewaters are discharged to the San Gabriel River through one of three separate outfalls.

AGS will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities at 40 CFR 423.13(d)(1). These ELGs set numeric limitations for chromium (total) and zinc (0.2 mg/L and 1.0 mg/L, respectively), while establishing narrative criteria for priority pollutants (no detectable quantity).

Although South Coast Air Quality Management District (SCAQMD) prohibited the use of chromium-based compounds in open circulating water cooling towers under Rule 1404, effective January 1, 1990, chromium continues to be detected in Los Cerritos Channel. Intake sampling conducted by AGS as part of its compliance monitoring program has repeatedly detected zinc. The presence of these pollutants in the makeup water source may trigger ELG exceedances when concentrated in the cooling tower. Effluent limitations for cooling tower blowdown must be met at the point of discharge from the cooling tower prior to combination with any other waste stream. The potential for an exceedance could necessitate treatment of the cooling tower blowdown for metals prior to discharge.

Likewise, WQBELs for other parameters may be established at the final discharge point based on the SIP. These WQBELs may present compliance challenges for AGS when converting to a wet cooling tower system, principally due to elevated background concentrations for metals in Los Cerritos Channel. The SIP does make an allowance for intake credits under some circumstances, but none would be applicable to AGS due to the fact that a cooling tower effectively changes the intake water characteristics by concentrating pollutants (through evaporation) by as much as 50 percent above their initial levels. In addition, the current receiving water (San Gabriel River) may not meet the criteria establishing it as "hydrologically connected" to Los Cerritos Channel (State Water Board 2000).

Data submitted by AGS in support of its NPDES renewal application demonstrates a reasonable potential to exceed effluent limitations for copper, zinc, and cyanide (AES 2004). These assessments reflect the existing once-through cooling system and, for zinc and copper, are primarily driven by the elevated concentrations detected in the intake water at AGS. Assuming the same source water, any reasonable potential associated with wet cooling tower operations would likely increase and may require an effluent treatment system, such as filtration or precipitation technologies, to meet NPDES permit conditions.

Thermal limits for an estuary impose a maximum discharge temperature of 20º F above the receiving water's natural temperature (State Water Board 1972). It is unclear if AGS will be able to meet this thermal limitation based on the current once-through configuration, with discharge temperatures reaching as high as 100 ºF and ambient water temperatures in the mid to upper 60s. Wet cooling towers will enable AGS to meet this limitation because blowdown discharge will be taken from the cold water side of the system, ensuring an effluent discharge temperature not in excess of 83º F for normal operations (not including heat treatments). This temperature is within the required 20º F range of ambient temperatures in the San Gabriel River.

Contra Costa Power Plant

At maximum operation, wet cooling towers at Contra Costa Power Plant (CCPP) will result in an effluent discharge of approximately 13 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, floor drain wastes, and cleaning wastes. These low-volume wastes may add an additional 0.5 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, CCPP will be required to modify its existing individual wastewater discharge (NPDES) permit.

Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0004863, as implemented by Central Valley Regional Water Board Order R-01-107. All once-through cooling water and process wastewaters are discharged through a shoreline outfall to the San Joaquin River. The existing order contains effluent limitations based on the California Toxics Rule (CTR) and the1972 Thermal Plan and the Basin Plan.

CCPP will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities at 40 CFR 423.13(d)(1). These ELGs set numeric limitations for chromium (total) and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). Although Bay Area Air Quality Management District (BAAQMD) prohibited chromium-based compounds in open circulating water cooling towers under Rule 10, effective March 1, 1990, chromium and zinc have been detected the San Joaquin River, although specific information describing the intake water at CCPP was not available for review.

The presence of chromium or zinc in the makeup water source may trigger ELG exceedances when concentrated in the cooling tower and discharged with the final effluent. Effluent limitations for cooling tower blowdown must be met at the point of discharge from the cooling tower prior to combination with any other waste stream. The potential for an exceedance could necessitate treatment of the blowdown for metals prior to discharge.

The Thermal Plan limits the discharge of elevated-temperature wastes in estuaries to no more than 86º F. CCPP applied for, and received, an exception to this Thermal Plan requirement. The current order permits the discharge of elevated-temperature wastes that do not exceed the natural receiving water temperature by more than 37º F at flood tide (Central Valley Regional Water Board 2001). Because cooling tower blowdown will be taken from the "cold" side of the tower, conversion to a wet cooling system will significantly reduce the discharge temperature (to less than 78º F) and the size of any related thermal plume in the receiving water, thus enabling CCPP to meet the initial requirements of the Thermal Plan.

Diablo Canyon Power Plant

At maximum operation, wet cooling towers at Diablo Canyon Power Plant (DCPP) will result in an effluent discharge of approximately 72 mgd of blowdown in addition to other in-plant waste streams, such as regeneration wastes, boiler blowdown, and treated sanitary wastes. These low-volume wastes may add an additional 20 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, DCPP will be required to modify its existing individual wastewater discharge (NPDES) permit.

Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES permit CA0003751 as implemented by Central Coast Regional Water Board Order RB3-2003-0009. The existing order contains effluent limitations based on the 2001 California Ocean Plan and the 1972 Thermal Plan.

DCPP will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities at 40 CFR 423.13(d)(1). These ELGs set numeric limitations for chromium (total) and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity).

Thermal discharge standards are based on narrative criteria established for discharges to coastal waters under the Thermal Plan, which requires that existing discharges of elevated-temperature wastes comply with effluent limitations necessary to assure the protection of designated beneficial uses. The Central Coast Regional Water Board has implemented this provision by establishing a maximum discharge temperature of no more than 22º F in excess of the temperature of the receiving water during normal operations (Central Coast Regional Water Board 2003).

Because cooling tower blowdown will be taken from the “cold” side of the tower, conversion to a wet cooling system will significantly reduce the discharge temperature (to less than 78º F) and the size of any related thermal plume in the receiving water.

El Segundo Generating Station

At maximum operation, wet cooling towers at El Segundo Generating Station (ESGS) will result in an effluent discharge of approximately 14 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, sanitary wastes, and cleaning wastes. These low-volume wastes may add an additional 1.1 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, ESGS will be required to modify its existing individual wastewater discharge (NPDES) permit.

Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0001147, as implemented by Los Angeles Regional Water Board Order 00-084. All wastewaters are discharged to the Pacific Ocean through a submerged conduit extending approximately 2,100 feet offshore. The existing order contains effluent limitations based on the 1997 Ocean Plan and 1972 Thermal Plan.

ESGS will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities at 40 CFR 423.13(d)(1). These ELGs set numeric limitations for chromium (total) and zinc (0.2 mg/L and 1.0 mg/L, respectively), while establishing narrative criteria for priority pollutants (no detectable quantity). Although the South Coast Air Quality Management District (SCAQMD) prohibited the use of chromium-based compounds in open circulating water cooling towers under Rule 1404, effective January 1, 1990, chromium continues to be detected in the intake water samples collected by ESGS as part of its compliance monitoring program. The presence of chromium or zinc in the makeup water source may trigger exceedances of the ELGs when concentrated in the cooling tower and discharged with the final effluent. Effluent limitations for cooling tower blowdown must be met at the point of discharge from the cooling tower prior to combination with any other waste stream. The potential for an exceedance could necessitate treatment of the blowdown for metals prior to discharge.

Likewise, water quality–based effluent limits (WQBELs) for other parameters may be established at the final discharge point based on the Ocean Plan. Data submitted by ESGS in support of its NPDES renewal application do not demonstrate a reasonable potential to exceed effluent limitations for common metals, although zinc, copper, chromium, lead, and mercury have been detected in the intake water (El Segundo Power 2004). An initial assessment of the data does not suggest that levels of these pollutants are high enough to warrant consideration of an effluent treatment system, although the changes to the facility’s dilution model that will occur after adopting wet cooling towers may change the basis for comparison.

Thermal discharge standards are based on narrative criteria established for coastal discharges under the Thermal Plan, which requires existing discharges of elevated-temperature wastes to comply with effluent limitations necessary to assure the protection of designated beneficial uses. The Los Angeles Regional Water Board has implemented this provision by establishing a maximum discharge temperature of 105º F during normal operations in Order 00-084 (Los Angeles Regional Water Board 2000). Information available for review indicates ESGS has consistently been able to comply with this requirement. Because cooling tower blowdown will be taken from the "cold" side of the tower, conversion to a wet cooling system will significantly reduce the discharge temperature (to less than 81º F) and the size of any related thermal plume in the receiving water.

Harbor Generating Station

At maximum operation, the Harbor Generating Station (HGS) wet cooling towers will result in an effluent discharge of 3.0 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, regeneration wastes, and cleaning wastes. These low-volume wastes may add an additional 0.0125 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, HGS will be required to modify its existing individual wastewater discharge (NPDES) permit.

Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0000361as implemented by Los Angeles Regional Water Board Order R4-2003-0101. All wastewaters are discharged to the West Basin of ILAHC. The existing order contains effluent limitations based on the California Toxics Rule (CTR) and 1972 Thermal Plan.

HGS will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities at 40 CFR 423.13(d)(1). These ELGs set numeric limitations for chromium (total) and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). Although the SCAQMD prohibited the use of chromium-based compounds in open circulating water cooling towers under Rule 1404, effective January 1, 1990, chromium and zinc continue to be detected in the Los Angeles Harbor.

The presence of chromium or zinc in the makeup water source may trigger ELG exceedances when concentrated in the cooling tower and discharged with the final effluent. Effluent limitations for cooling tower blowdown must be met at the point of discharge from the cooling tower prior to combination with any other waste stream. The potential for an exceedance could necessitate treatment of the blowdown for metals prior to discharge.

Likewise, water quality–based effluent limits (WQBELs) for other parameters may be established at the final discharge point based on the CTR. Effluent data were not available for review for HGS, but the 2002 303(d) list identifies several segments of the

Los Angles Harbor as impaired for cadmium, chromium, lead, mercury, and zinc (USEPA 2002). Total maximum daily loads (TMDLs) for the Los Angeles Harbor may be established in the future, with specific load allocations (LAs) for these pollutants applied to HGS.

Thermal discharge standards are based on narrative criteria established for discharges within enclosed bays under the Thermal Plan, which requires existing discharges of elevated temperature wastes to comply with effluent limitations necessary to assure the protection of designated beneficial uses. The Los Angeles Regional Water Board has implemented this provision in Order R4-2003-0101 by establishing a maximum discharge temperature of 94º F during normal operations (Los Angeles Regional Water Board 2003). Information available for review indicates HGS has consistently been able to comply with this requirement. Because cooling tower blowdown will be taken from the "cold" side of the tower, conversion to a wet cooling system will significantly reduce the discharge temperature (to less than 80º F) and the size of any related thermal plume in the receiving water.

Haynes Generating Station

At maximum operation, wet cooling towers at Haynes Generating Station (HnGS) will result in an effluent discharge of approximately 24 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, treated sanitary waste, and cleaning wastes. These low-volume wastes may add an additional 0.5 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, HnGS will be required to modify its existing individual wastewater discharge (NPDES) permit. Effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0000353, as implemented by Los Angeles Regional Water Board Order 00-081. All wastewaters are discharged to the San Gabriel River through one of six separate outfalls.

HnGS will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities at 40 CFR 423.13(d)(1). These ELGs set numeric limitations for chromium (total) and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). Although the SCAQMD prohibited the use of chromium-based compounds in open circulating water cooling towers under Rule 1404, effective January 1, 1990, chromium continues to be detected in the Long Beach Marina. Likewise, intake sampling conducted by HnGS as part of its compliance monitoring program has repeatedly detected zinc. The presence of these pollutants in the makeup water source may trigger exceedances of the ELGs when concentrated in the cooling tower. Effluent limitations for cooling tower blowdown must be met at the point of discharge from the cooling tower prior to combination with any other waste stream. The potential for an exceedance could necessitate treatment of the blowdown for metals prior to discharge.

Likewise, WQBELs for other parameters may be established at the final discharge point based on the SIP. These WQBELs may present compliance challenges for HnGS when converting to a wet cooling tower system, principally due to elevated background concentrations for metals in the Long Beach Marina. The SIP does make an allowance for intake credits under some circumstances, but none would be applicable to HnGS due to the fact that a cooling tower effectively changes the characteristics of the intake water by concentrating pollutants (through evaporation) by as much as 50 percent above their initial levels. In addition, the current receiving water (San Gabriel River) may not meet the criteria establishing it as “hydrologically connected” to the Long Beach Marina (State Water Board 2000).

Data submitted by HnGS in support of its NPDES renewal application demonstrates a reasonable potential to exceed effluent limitations for copper, mercury, nickel, and zinc (LADWP 2004). These assessments reflect the existing once-through cooling system and are primarily driven by the elevated concentrations detected in the intake water at HnGS. Assuming the same source water, any reasonable potential associated with wet cooling tower operations would likely increase and may require an effluent treatment system, such as filtration or precipitation technologies, in order to meet NPDES permit conditions.

Thermal limits for an estuary impose a maximum discharge temperature of 20º F above the natural temperature of the receiving water (State Water Board 1972). It is unclear if HnGS will be able to meet this thermal limitation based on the current once-through configuration, with discharge temperatures reaching as high as 100º F and ambient water temperatures in the mid- to upper 60s. Wet cooling towers will enable HnGS to meet this limitation because blowdown discharge will be taken from the cold water side of the system, ensuring an effluent discharge temperature not in excess of 81º F for normal operations (not including heat treatments). This temperature is within the required 20º F range of ambient temperatures in the San Gabriel River.

Huntington Beach Generating Station

At maximum operation, wet cooling towers at Huntington Beach Generating Station (HBGS) will result in an effluent discharge of approximately 17 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, floor drain wastes, and cleaning wastes. These low volume wastes may add an additional 1.5 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, HBGS will be required to modify its existing individual wastewater discharge (NPDES) permit.

Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0001163 as implemented by Santa Ana Regional Water Board Order R8-2006-0011. All once-through cooling water and process wastewaters are discharged through a submerged outfall extending approximately 1,200 feet offshore into the Pacific Ocean. The existing order contains effluent limitations based on the 2005 Ocean Plan and the 1972 Thermal Plan.

HBGS will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities at 40 CFR 423.13(d)(1). These ELGs set numeric limitations for chromium (total) and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). SCAQMD prohibited the use of chromium-based compounds in open circulating water cooling towers under Rule 1404, effective January 1, 1990.

The presence of chromium or zinc in the makeup water source may trigger exceedances of the ELGs when concentrated in the cooling tower and discharged with the final effluent. Effluent limitations for cooling tower blowdown must be met at the point of discharge from the cooling tower prior to combination with any other waste stream. The potential for an exceedance could necessitate treatment of the blowdown for metals prior to discharge.

Thermal discharge standards are based on narrative criteria established for coastal discharges under the Thermal Plan, which requires existing discharges of elevated-temperature wastes to comply with effluent limitations necessary to assure the protection of designated beneficial uses. The Santa Ana Regional Water Board has implemented this provision in Order R8-2006-0011 by establishing a maximum discharge temperature of that may not exceed the receiving water's natural temperature by more than 30º F during normal operations (Santa Ana Regional Water Board 2006). Because cooling tower blowdown will be taken from the "cold" side of the tower, conversion to a wet cooling system will significantly reduce the discharge temperature (to less than 81º F) and the size of any related thermal plume in the receiving water.

Mandalay Generating Station

At maximum operation, wet cooling towers at Mandalay Generating Station (MGS) will result in an effluent discharge of 8.6 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, regeneration wastes, and cleaning wastes. These low volume wastes may add an additional 0.25 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, MGS will be required to modify its existing individual wastewater discharge (NPDES) permit. Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0001180 as implemented by Los Angeles Regional Water Board Order 01-057. All wastewaters are discharged to the Pacific Ocean via a rock-lined canal at the shoreline. The existing Order contains effluent limitations based on the 1997 Ocean Plan and the 1972 Thermal Plan.

MGS will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities at 40 CFR 423.13(d)(1). These ELGs set numeric limitations for chromium (total) and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). Although the use of chromium-based compounds in open circulating water cooling towers has been banned in since 1994, chromium and zinc continue to be detected in the Edison Canal.

The presence of chromium or zinc in the makeup water source may trigger ELG exceedances when concentrated in the cooling tower and discharged with the final effluent. Effluent limitations for cooling tower blowdown must be met at the point of discharge from the cooling tower prior to combination with any other waste stream. The potential for an exceedance could necessitate treatment of the blowdown for metals prior to discharge.

Likewise, water quality–based effluent limits (WQBELs) for other parameters may be established at the final discharge point based on the Ocean Plan. These WQBELs may present compliance challenges for MGS when converting to a wet cooling tower system, principally due to elevated background concentrations for metals in Channel Islands Harbor. MGS has had ongoing difficulty meeting existing effluent limitations for copper primarily due to elevated levels in the intake water.

Reliant Energy, Inc has argued that high levels of copper within Channel Islands Harbor and the Edison Canal are a result of other activities in the area and that MGS does not contribute copper, at any significant level, to the final discharge. The State Water Board agreed with the latter point, but rejected the appeal for permit relief, citing the Ocean Plan's definition of wastes as the "total discharge, of whatever origin" from the facility (State Water Board 2005). The State Water Board did note that MGS could modify its existing discharge structure to increase the level of dilution and thereby increase the monthly effluent limitations. Such modifications, or other treatment measures, may become necessary with a wet cooling tower system because the tower effectively changes the characteristics of the intake water by concentrating pollutants (through evaporation) by as much as 50 percent above their initial levels.

In addition to copper, data submitted by MGS in support of its NPDES renewal application demonstrates a reasonable potential to exceed effluent limitations for cadmium, chromium, and zinc (Reliant 2004). These assessments reflect the existing once-through cooling system and are primarily driven by the elevated concentrations of these pollutants detected in the intake water at MGS. Assuming the same source water, any reasonable potential associated with wet cooling tower operations would likely increase and may require an effluent treatment system, such as filtration or precipitation technologies, to meet NPDES permit conditions.

Thermal discharge standards are based on narrative criteria established for coastal discharges under the Thermal Plan, which requires that existing discharges of elevated-temperature wastes comply with effluent limitations necessary to assure the protection of designated beneficial uses. The Los Angeles Regional Water Board has implemented this provision by establishing a maximum discharge temperature of 106º F during normal operations in Order 01-057 (Los Angeles Regional Water Board 2001). Information available for review indicates MGS has consistently been able to comply with this requirement. Because cooling tower blowdown will be taken from the "cold" side of the tower, conversion to a wet cooling system will significantly reduce the discharge temperature (to less than 80º F) and the size of any related thermal plume in the receiving water.

Morro Bay Power Plant

At maximum operation, wet cooling towers at Morro Bay Power Plant (MBPP) will result in an effluent discharge of 15 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, regeneration wastes, and cleaning wastes. These low volume wastes may add an additional 0.5 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, MBPP will be required to modify its existing individual wastewater discharge (NPDES) permit. All wastewaters are discharged to the Estero Bay through a submerged conduit. The existing Order contains effluent limitations based on the 1997 Ocean Plan and the 1972 Thermal Plan.

MBPP will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities at 40 CFR 423.13(d)(1). These ELGs set numeric limitations for chromium (total) and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity.

The presence of chromium or zinc in the makeup water source may trigger ELG exceedances when concentrated in the cooling tower and discharged with the final effluent. Effluent limitations for cooling tower blowdown must be met at the point of discharge from the cooling tower prior to combination with any other waste stream. The potential for an exceedance could necessitate treatment of the blowdown for metals prior to discharge.

Moss Landing Power Plant

At maximum operation, wet cooling towers at Moss Landing Power Plant (MLPP) will result in an effluent discharge of approximately 37 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, floor drain wastes, and cleaning wastes. These low volume wastes may add an additional 1.0 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, MLPP will be required to modify its existing individual wastewater discharge (NPDES) permit.

Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0006254 as implemented by Central Coast Regional Water Board Order 00-041. All once-through cooling water and process wastewaters are discharged through a submerged outfall extending offshore into the Pacific Ocean. The existing Order contains effluent limitations based on the 1997 Ocean Plan and the 1972 Thermal Plan.

Thermal discharge standards are based on narrative criteria established for discharges to coastal waters under the Thermal Plan, which requires that existing discharges of elevated-temperature wastes comply with effluent limitations necessary to assure the protection of designated beneficial uses. The Central Coast Regional Water Board has implemented this provision by establishing a maximum discharge temperature of no more than 26º F to 34º F in excess of the temperature of the receiving water during normal operations, depending on which units are operating (Central Coast Regional Water Board 2000).

Ormond Beach Generating Station

At maximum operation, wet cooling towers at Ormond Beach Generating Station (OBGS) will result in an effluent discharge of 31 mgd of blowdown in addition to other in-plant waste streams such as boiler blowdown, regeneration wastes, and cleaning wastes. These low volume wastes may add an additional 0.75 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, OBGS will be required to modify its existing individual wastewater discharge (NPDES) permit.

Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0001198, as implemented by Los Angeles Regional Water Board Order 01-092. All wastewaters are discharged to the Pacific Ocean through a submerged conduit extending approximately 1,790 feet offshore. The existing order contains effluent limitations based on the 1997 Ocean Plan and 1972 Thermal Plan.

OBGS will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities at 40 CFR 423.13(d)(1). These ELGs set numeric limitations for chromium (total) and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). The use of chromium-based compounds in open circulating water cooling towers has been banned in since 1994.

Available data describing the intake water do not indicate high levels of chromium or zinc, although elevated concentrations of either constituent in the makeup water source may trigger ELG exceedances when concentrated in the cooling tower and discharged with the final effluent. Effluent limitations for cooling tower blowdown must be met at the point of discharge from the cooling tower prior to combination with any other waste stream. The potential for an exceedance could necessitate treatment of the blowdown waste stream for metals prior to discharge.

Likewise, water quality–based effluent limits (WQBELs) for other parameters may be established at the final discharge point based on the Ocean Plan. Data submitted by OBGS in support of its NPDES renewal application do not demonstrate a reasonable potential to exceed effluent limitations for common metals, although zinc, copper, and chromium have been detected in the intake water (Reliant 2004).

An initial assessment of the available data does not suggest these pollutant levels are high enough to warrant consideration of an effluent treatment system, although changes to the facility's dilution model that will occur after adopting wet cooling towers may change the basis for comparison.

Thermal discharge standards are based on narrative criteria established for coastal discharges under the Thermal Plan, which requires that existing discharges of elevated-temperature wastes comply with effluent limitations necessary to assure the protection of designated beneficial uses. The Los Angeles Regional Water Board has implemented this provision by establishing a maximum discharge temperature of 105º F during normal operations in Order 01-092 (Los Angeles Regional Water Board 2001). Information available for review indicates OBGS has consistently been able to comply with this requirement. Because cooling tower blowdown will be taken from the "cold" side of the tower, conversion to a wet cooling system will significantly reduce the discharge temperature (to less than 80º F) and the size of any related thermal plume in the receiving water.

Pittsburg Power Plant

At maximum operation, wet cooling towers at Pittsburg Power Plant (PPP) will result in an effluent discharge of approximately 13 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, floor drain wastes, and cleaning wastes. These low-volume wastes may add an additional 0.8 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, PPP will be required to modify its existing individual wastewater discharge (NPDES) permit.

Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0004880 as implemented by San Francisco Bay Regional Water Board Order R2-2002-0072. All once-through cooling water and process wastewaters are discharged through a shoreline outfall to Suisun Bay. The existing order contains effluent limitations based on the California Toxics Rule (CTR), the 1972 Thermal Plan and the San Francisco Bay Basin Water Quality Control Plan ("Basin Plan").

PPP will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities at 40 CFR 423.13(d)(1). These ELGs set numeric limitations for chromium (total) and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). Although BAAQMD prohibited chromium-based compounds in open circulating water cooling towers under Rule 10, effective March 1, 1990, chromium and zinc have been detected in the intake water samples collected by PPP as part of its compliance monitoring program.

The presence of chromium or zinc in the makeup water source may trigger ELG exceedances when concentrated in the cooling tower and discharged with the final effluent. Effluent limitations for cooling tower blowdown must be met at the point of discharge from the cooling tower prior to combination with any other waste stream. The potential for an exceedance could necessitate treatment of the blowdown for metals prior to discharge.

The Thermal Plan limits the discharge of elevated-temperature wastes in estuaries to no more than 86º F. PPP applied for, and received, an exception to this Thermal Plan requirement. The current order permits the discharge of elevated-temperature wastes that do not exceed the natural receiving water temperature by more than 28º F at flood tide (San Francisco Bay Regional Water Board 2002). Because cooling tower blowdown will be taken from the "cold" side of the tower, conversion to a wet cooling system will significantly reduce the discharge temperature (to less than 78º F) and the size of any related thermal plume in the receiving water, thus enabling PPP to meet the initial requirements of the Thermal Plan.

San Onofre Nuclear Generating Station

At maximum operation, wet cooling towers at San Onofre Nuclear Generating Station (SONGS) will result in an effluent discharge of approximately 73 mgd of blowdown in addition to other in-plant waste streams, such as regeneration wastes, boiler blowdown, and treated sanitary wastes. These low-volume wastes may add an additional 20 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, SONGS will be required to modify its existing individual wastewater discharge (NPDES) permit.

Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES permits CA0108073 (Unit 2) and CA0108181 (Unit 3), as implemented by San Diego Regional Water Board orders R9-2005-0005 (Unit 2) and R9-2005-0006 (Unit 3). All wastewaters are discharged to the Pacific Ocean through discharge conduits extending 8,350 feet and 5,900 feet offshore, terminating at a depth of 49 feet. The existing order contains effluent limitations based on the 2001 California Ocean Plan.

SONGS will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities at 40 CFR 423.13(d)(1). These ELGs set numeric limitations for chromium (total) and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity).

Although the use of chromium-based compounds in open circulating water cooling towers has been prohibited since 1994, chromium has been detected at elevated levels in the intake samples collected by SONGS. The presence of chromium in the makeup water source may trigger exceedances of the ELGs when concentrated in the cooling tower and discharged with the final effluent. Effluent limitations for cooling tower blowdown must be met at the point of discharge from the cooling tower prior to combination with any other waste stream. The potential for an exceedance could necessitate treatment of the blowdown for metals prior to discharge.

Thermal discharge standards are based on narrative criteria established for discharges to coastal waters under the Thermal Plan, which requires that existing discharges of elevated-temperature wastes comply with effluent limitations necessary to assure the protection of designated beneficial uses. The San Diego Regional Water Board has implemented this provision by establishing a maximum discharge temperature of no more than 25º F in excess of the temperature of the receiving water during normal operations (San Diego Regional Water Board 2005a and 2005b).

Information available for review indicates SONGS has consistently been able to comply with this requirement. Because cooling tower blowdown will be taken from the “cold” side of the tower, conversion to a wet cooling system will significantly reduce the discharge temperature (to less than 82º F) and the size of any related thermal plume in the receiving water.

Scattergood Generating Station

At maximum operation, wet cooling towers at Scattergood Generating Station (SGS) will result in an effluent discharge of approximately 15 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, floor drain wastes, and cleaning wastes. These low-volume wastes may add an additional 0.25 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, SGS will be required to modify its existing individual wastewater discharge (NPDES) permit.

Current effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0000370, as implemented by Los Angeles Regional Water Board Order 00-083. All wastewaters are discharged to the Pacific Ocean through a submerged conduit extending approximately 1,200 feet offshore. The existing order contains effluent limitations based on the 1997 Ocean Plan and 1972 Thermal Plan.

SGS will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities at 40 CFR 423.13(d)(1). These ELGs set numeric limitations for chromium (total) and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity).

Although the SCAQMD prohibited the use of chromium-based compounds in open circulating water cooling towers under Rule 1404, effective January 1, 1990, chromium and zinc continue to be detected in the intake water samples collected by SGS as part of its compliance monitoring program. The presence of chromium or zinc in the makeup water source may trigger exceedances of the ELGs when concentrated in the cooling tower and discharged with the final effluent. Effluent limitations for cooling tower blowdown must be met at the point of discharge from the cooling tower prior to combination with any other waste stream. The potential for an exceedance could necessitate treatment of the blowdown for metals prior to discharge.

Likewise, water quality–based effluent limits (WQBELs) for other parameters may be established at the final discharge point based on the Ocean Plan. Data submitted by SGS in support of its NPDES renewal application do not demonstrate a reasonable potential to exceed effluent limitations for common metals, although zinc, copper, chromium, and lead have been detected in the intake water (LADWP 2004). An initial assessment of the data does not suggest the levels of these pollutants are high enough to warrant consideration of an effluent treatment system, although changes to the facility's dilution model that will occur after adopting wet cooling towers may change the basis for comparison.

Thermal discharge standards are based on narrative criteria established for coastal discharges under the Thermal Plan, which requires that existing discharges of elevated-temperature wastes comply with effluent limitations necessary to assure the protection of designated beneficial uses. The Los Angeles Regional Water Board has implemented this provision by establishing a maximum discharge temperature of 100º F during normal operations in Order 00-083 (Los Angeles Regional Water Board 2000). Information available for review indicates SGS has consistently been able to comply with this requirement. Because cooling tower blowdown will be taken from the "cold" side of the tower, conversion to a wet cooling system will significantly reduce the discharge temperature (to less than 81º F) and the size of any related thermal plume in the receiving water.

Noise

Some alternate cooling technologies such as wet or dry cooling may result in higher ambient noise levels. In contrast, the noise levels from once-though cooling are rarely audible off site.

There are no specific regulations or criteria regarding noise for once through cooling systems. When determining noise criteria for a power plant, the plant operators will need to comply with any applicable city or county noise ordinances. Furthermore, the plant operators will need to ensure that there will be no adverse impacts, per CEQA, to any "sensitive receptors" (e.g., homes, hospitals, nursing homes, etc.) Possible mitigation measures include installation of low-noise fans or sound barriers.

The potential noise levels are site-specific and cannot be addressed in further detail by this staff report.

Land Use Planning

Construction of conventional wet cooling towers is within compliance of local use requirements, with the exception of Redondo Beach (Tetra Tech 2008). In some areas, if plume-abated towers are determined to be necessary as a result of visual impacts, then local height restrictions may be violated. These potential conflicts with local land use requirements will need to be addressed during the environmental review for each project and appropriate mitigation developed or variances allowed by the local planning agencies.

Utilities and Service Systems (including Grid Reliability)

The California Ocean Protection Council (OPC) and the State Water Board have commissioned an Electric Grid Reliability study (Jones & Stokes 2008) to investigate concerns about the State Water Board's pending policy decision on the use of seawater at coastal power plants. These concerns focused on the possible significant negative impact on the overall reliability of the state's electricity grid. The Electric Grid Reliability study also examined the potential indirect impacts to the environment that could result from the Water Board's policy.

Preliminary results of the study indicate that while the State Water Board's pending OTC policy does have potential to negatively affect electric reliability, proper planning can compensate for any plant retirements and prevent reliability problems, provided the industry has sufficient time to respond.

Seven years are needed to plan, site, permit, and construct a new major transmission line. However, the vast majority of the transmission upgrades identified in the Electric Grid Reliability study required to compensate for OTC plant retirements are relatively modest, requiring only 1-3 years to construct and place in-service. Furthermore, the transmission planning process in the state has improved considerably in recent years. The state seems well poised to compensate for most OTC plant retirements in the 2012 and beyond time period by constructing transmission upgrades to tap into the excess generating capacity that is projected to occur then.

While grid reliability can be maintained throughout the retrofit, each plant will require time to plan and permit the alternative cooling systems. The general consensus of the energy industry is that five years is needed to plan, site, permit, and construct a new major power plant. Permitting alone may take one year or more, with the larger capacity factor and nuclear plants requiring more time to plan and permit. If plant operators opt to re-power, the permitting will be considerably more extensive.

According to the grid modeling effort, overall costs could range from as little as around $100 million to as much as $11 billion, depending on how and when the policy is enacted, and how the energy industry responds to OTC plant retirements. Though transmission system upgrades are identified as the least-cost alternative for replacing OTC retirements, doing so presents its own challenges because many upgrades would be needed out of the state. Careful analysis is needed to develop an optimal combination of new plant construction and transmission system improvements to ensure the greatest benefit to the ratepayer following any OTC plant retirements, and to ensure such infrastructure can be developed in a timely manner.

Growth-Inducing Impacts

The CEQA Guidelines (CCR, Title 14, Chapter 3) provide the following direction for the examination of growth-inducing impacts:

(d) Growth-Inducing Impact of the Proposed Project. Discuss the ways in which the proposed project could foster economic or population growth, or the construction of additional housing, either directly or indirectly, in the surrounding environment. Included in this are projects which would remove obstacles to population growth (a major expansion of a waste water treatment plant might, for example, allow for more construction in service areas). Increases in the population may tax existing community service facilities, requiring construction of new facilities that could cause significant environmental effects. Also discuss the characteristic of some projects which may encourage and facilitate other activities that could significantly affect the environment, either individually or cumulatively. It must not be assumed that growth in any area is necessarily beneficial, detrimental, or of little significance to the environment. (CCR, Title 14, §15126.2(d))

Implementation of this Policy will not result in an increase in power generation and is, therefore, not expected to induce additional growth.

Cumulative Impacts

The CEQA Guidelines provide the following definition of cumulative impacts:

"Cumulative impacts" refers to two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts.
(a) The individual effects may be changes resulting from a single project or a number of separate projects.
(b) The cumulative impact from several projects is the change in the environment which results from the incremental impact of the project when added to other closely related past, present, and reasonably foreseeable probable future projects. Cumulative impacts can result from individually minor but collectively significant projects taking place over a period of time. (CCR, Title 14, §15355)

The fundamental purpose of the cumulative impact analysis is to ensure that the potential environmental impacts of any individual project are not considered in isolation. Impacts that are individually less than significant on a project-by-project basis, could pose a potentially significant impact when considered with the impacts of other projects. The cumulative impact analysis need not be performed at the same level of detail as a "project level" analysis but must be sufficient to disclose potential combined effects that could constitute a significant adverse impact.

USEPA conducted an economics and benefits analysis as part of the Clean Water Act § 316(b) rulemaking process. The economics and benefits analyses for the Phase I and Phase II regulations can be found online at: **http://www.epa.gov/waterscience/316b/**. For California, social costs of compliance (pre-tax basis, and including federal, state and local administrative costs) were estimated by USEPA to be $31.7 million.

In California, USEPA estimated that the total current annual impingement and entrainment losses due to OTC were 28.9 million pounds of fishery yield and 43.6 future biomass production due to once through cooling.

BRIEF ECONOMIC ANALYSIS

In recent years, alternative cooling methods—particularly wet and dry closed-cycle systems— have increasingly become the preferred approach for new steam electric facilities. The majority of all new conventional steam units constructed in the last two decades have used a closed-cycle system, with nearly all new combined-cycle units adopting this approach.

The economics and engineering considerations of a closed-cycle system are more favorable when part of a new facility's initial construction, or as a major overhaul of an existing facility (re-power).

Altering the cooling system at an existing facility increases costs and can adversely impact the performance of the generating units. The decision to retrofit an existing facility from once-through cooling to closed-cycle is usually driven by extenuating circumstances that mandate a conversion, such as regulatory oversight or changes in water availability.

Re-powering, on the other hand, is a more comprehensive upgrade or overhaul to the facility's generating system, including the boiler and turbine. When combined with a re-powering project, closed-cycle dry cooling systems become favorable, and may actually be preferable to continued use of once-through cooling. In some respects, a re-powered facility is similar to a new facility in that it has wider latitude in selecting an alternative cooling system. Re-power projects, as noted above, are more comprehensive in their modifications to the existing facility and often involve the complete demolition and replacement of an existing facility. In doing so, closed cycle cooling options, particularly dry cooling, become more practical alternatives.

In California, four of the original 21 coastal power plants are proceeding with re-powering projects that eliminate the use of once-through cooling water, either in whole or in part—Humboldt Bay, Long Beach, El Segundo, and Encina. A fifth close cycle cooled plant, Gateway, is being developed adjacent to the existing Contra Costa Plant.

Taking into account only physical and logistical factors, the Tetra Tech study evaluates each facility with respect to technologies that can achieve a 90–95 percent reduction of I/E impacts as discussed in the 2006 OPC resolution. These include flow reduction measures, such as closed-cycle cooling or, in a few instances, fine-mesh cylindrical wedgewire screens. However the Tetra Tech study primarily focuses on a cost-feasibility analysis of retrofitting the existing once-through system with a closed cycle wet cooling system (evaporative cooling towers).

Below is the summary of annual facility costs for the plants that were analyzed by Tetra Tech. Long Beach, El Segundo, Encina, Humboldt Bay, and Potrero were not part of the analysis because they have proposed to adopt alternative cooling or are shutting down at some point in the near future (Potrero, pending the outcome of the San Francisco grid reliability study). The table presents the total costs including the startup costs, O&M and energy penalty estimates. All annual costs are amortized over 20 years at seven percent.

Table 18. Annual Cost Summary – Facility [bbb]

Facility	Category[a]	20-year annualized cost ($) [b][c]	Rated Capacity (GWh)	Cost Per MWh ($/MWh)	2006 Net Output (GWh)	Cost $/MWh
Alamitos	ST	25,400,000	17,082	1.49	1,677	15.15
Contra Costa	ST	9,900,000	5,957	1.66	142	69.86
Diablo Canyon	N	233,700,000	19,272	12.13	18,465	12.66
Harbor	CC	2,700,000	2,059	1.36	183	15.28
Haynes [d]	CC	6,000,000	5,037	1.19	2,065	2.91
Haynes [d]	ST	13,900,000	9,145	1.52	2,263	6.14
Huntington Beach	ST	15,400,000	7,709	2.00	1,141	13.50
Mandalay	ST	5,800,000	3,767	1.54	312	18.57
Moss Landing [e]	CC	11,900,000	9,461	1.26	5,364	2.22
Moss Landing [e]	ST	21,700,000	12,299	1.76	1,043	20.81
Pittsburg	ST	12,700,000	12,264	1.04	447	28.40
San Onofre [f]	N	208,900,000	19,745	10.58	17,139	12.19
Scattergood	ST	18,600,000	7,034	2.64	1,497	12.42
All Facilities		**586,600,000**	**130,831**	**4.48**	**51,738**	**11.34**

(a) CC = combined cycle; ST = Simple cycle steam turbine (natural gas); N = Nuclear-fueled steam turbine
(b) 20-year annualized cost of all initial capital and startup costs, operations and maintenance, and energy penalty.
(c). Annual costs do not include any revenue loss associated with shutdown during construction. This loss is incurred in the first year of the project but not amortized over the 20-year project life span. Estimates of shutdown losses were developed for the following facilities:

Diablo Canyon: $727 million
San Onofre: $595 million
Haynes: $ 5 million
Moss Landing: $ 5 million

(d) Haynes operates one combined-cycle unit (unit 8) and four simple cycle units (units 1, 2, 5, & 6). Costs are specific for each unit type; facility-wide cost is the sum of both categories.
(e) Moss Landing operates two combined-cycle units (units 1 & 2) and two simple cycle units (units 6 & 7). Costs are specific for each unit type; facility-wide cost is the sum of both categories.
(f) 3-year average output for SONGS.

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bbb Costs for Morro Bay are not included because the analysis was developed based on the repowering project the previous owner (Duke Energy) had proposed for the facility. Cost estimates, therefore, are not directly comparable to the retrofit analyses conducted for the other coastal facilities. Based on a previous analysis prepared by Tetra Tech, Inc. for the Central Coast Regional Water Quality Control Board in 2002 and the general methodology of this study, the updated annual cost for Morro Bay is $9.6 million.

GWh = gigawatt hour
MWh = megawatt hour

In summary, based on the Tetra Tech restricted approach, the report estimated the annual cost to retrofit the 11 facilities above with wet cooling towers translates to 0.45 cents per kilowatt hour (kWh) based on the facilities' collective generating capacity. Compared with their 2006 generating output, the annual cost translates to 1.13 cents/kWh. Assuming an average electricity price of 12.93 cents/kWh, retrofit costs, if passed on to the ratepayer; represent an increase ranging from 3.5 to 8.7 percent.

While significant, these costs would fall hardest on the oldest facilities with their shorter remaining lives. Out of 54 power generating units at the 18 OTC facilities analyzed, 43 are 30 years or older (Table 18). It may be apparently more economical for these older generating units to follow the leads of the Long Beach, Humboldt Bay, Gateway, El Segundo, and Encina generating stations which look to eliminate once-through cooling through proposed re-powering projects. Re-powering allows the facilities to improve efficiency while reducing emissions, and eliminating entrainment and impingement impacts. It will be up to the individual facilities to determine their most economical response to the proposed I/E reduction requirements.

Table 19. California Coastal Facilities

Facility name (Location)	Design Flow (mgd)	Water Body Type	Unit	In-service Year	2001–2006 Capacity Utilization (%)	Dependable Capacity (MW)
Alamitos Generating Station (Long Beach)	1,077	Estuary	1	1956	6.7	175
			2	1957	8.7	175
			3	1961	27.7	326
			4	1962	20.8	324
			5	1969	27.4	485
			6	1966	22.2	485
Contra Costa Power Plant (Antioch)	440	Estuary	6	1964	16.4	340
			7	1964	23.1	340
Diablo Canyon Power Plant (Avila Beach)	2500	Ocean	1	1985	89.9	1103
			2	1986	89.3	1099
El Segundo Generation Station (El Segundo)	424	Ocean	3	1964	19.4	335
			4	1965	24.8	335
Encina Power Station (Carlsbad)	857	Ocean	1	1954	18.7	107
			2	1956	21	104
			3	1958	25.1	110
			4	1973	36	300
			5	1978	33	330
Harbor Generating Station (Los Angeles)	108	Enclosed Bay/Harbor	CC	1994	20.5	227
Haynes Generating Station (Long Beach)	966	Estuary	1	1962	20.5	1606
			2	1963		
			5	1966		

Facility name (Location)	Design Flow (mgd)	Water Body Type	Unit	In-service Year	2001–2006 Capacity Utilization (%)	Dependable Capacity (MW)
			6	1967		
			8	2005		
Huntington Beach Generating Station (Huntington Beach)	516	Ocean	1	1958	31.5	215
			2	1958	31	215
			3	2002	9.6	225
			4	2003	8.5	225
Mandalay Generating Station (Oxnard)	253	Enclosed Bay/Harbor	1	1959	20.6	218
			2	1959	23.4	218
Morro Bay Power Plant (Morro Bay)	552	Estuary	3	1962	18.8	300
			4	1963	18.8	300
Moss Landing Power Plant (Moss Landing)	1224	Enclosed Bay/Harbor	1	2002	41.1	540
			2	2002	41.1	540
			6	1967	19.7	702
			7	1968	24.2	702
Ormond Beach Generating Station (Oxnard)	688	Ocean	1	1971	16.3	806
			2	1973	17.7	806
Pittsburg Power Plant (Pittsburg)	495	Estuary	5	1960	23.7	325
			6	1961	21	325
			7	1972	23.5	720
(Potrero Power Plant (San Francisco)	226	Estuary	3	1956	38.1	207
Redondo Beach Generating Station (Redondo Beach)	871	Ocean	5	1954	4.9	179
			6	1957	5.6	175
			7	1967	22.2	493
			8	1967	19.6	493
San Onofre Nuclear Generating Station (San Clemente)	2574	Ocean	2	1983	86.8	1127
			3	1984	79.4	1127
Scattergood Generating Station (Los Angeles)	496	Ocean	1	1958	22.1	803
			2	1959		
			3	1974		
South Bay Power Plant (Chula Vista)	532	Estuary	1	1960	39.8	136
			2	1962	38.7	136
			3	1964	27.9	210
			4	1971	6.8	214

Note for Haynes and Scattergood - data for facility wide, unit level data unavailable.

According to the grid modeling effort (Jones and Stokes, 2008), overall costs of a statewide policy to replace OTC could range from as little as around $100 million to as much as $11 billion, depending on how and when the policy is enacted, and how the energy industry responds to OTC plant retirements. Though transmission system upgrades are identified as the least-cost alternative for replacing OTC retirements, doing so presents its own challenges because many upgrades would be needed out of the state. Careful analysis is needed to develop an optimal combination of new plant construction and transmission system improvements to ensure the greatest benefit to the ratepayer following any OTC plant retirements, and to ensure such infrastructure can be developed in a timely manner.

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APPENDIX A – STATEWIDE WATER QUALITY CONTROL POLICY ON THE USE OF COASTAL AND ESTUARINE WATERS FOR POWER PLANT COOLING

PRELIMINARY DRAFT FOR SCOPING DOCUMENT

1. Introduction

   A. Clean Water Act §316(b) requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. Section 316(b) is implemented through National Pollutant Discharge Elimination System (NPDES) permits, issued pursuant to Clean Water Act §402, which authorize the point source discharge of pollutants to navigable waters. The State Water Board is designated as the state water pollution control agency for all purposes stated in the Clean Water Act.

   B. The State Water Resources Control Board (State Water Board) and Regional Water Quality Control Boards (Regional Water Boards) (collectively Water Boards) are authorized to issue NPDES permits to point source dischargers in California.

   C. Currently, there are no applicable nationwide standards implementing §316(b) for existing power plants. Consequently, the Water Boards must implement §316(b) on a case-by-case basis, using best professional judgment.

   D. State law in California Water Code §13142.5 also requires that new and expanded coastal power plants using seawater for cooling utilize the best available site, design, technology, and mitigation measures feasible to minimize the intake and mortality of all forms of marine life.

   E. The State Water Board is responsible for adopting state policy for water quality control, which may consist of water quality principles, guidelines, and objectives deemed essential for water quality control.

   F. This policy establishes uniform requirements governing the exercise by the Water Boards of best professional judgment in the implementation of §316(b) for cooling water intake structures at existing coastal and estuarine power plants that must be implemented in NPDES permits.

   G. The intent of this policy is to ensure that the beneficial uses of the State's coastal and estuarine waters are protected while also ensuring that the electrical power needs essential for the welfare of the citizens of the State are met.

H. To prevent disruption in the State's electrical power supply, the State Water Board will convene a Statewide Task Force, which will include representatives from the California Energy Commission, the Public Utilities Commission, the State Coastal Commission, the California State Lands Commission, the California Air Resources Board, and the California Independent Systems Operator (Cal ISO). The Statewide Task Force will assist the Water Boards in reviewing implementation plans and schedules submitted by dischargers pursuant to this policy.

I. To conserve the state's scarce water resources, the State Water Board encourages the use of recycled water for cooling water in lieu of marine, estuarine or freshwater.

2. Requirements for Existing Power Plants*

A. Compliance Alternatives

(1). Track 1. An existing power plant* must reduce intake flow and intake velocity, at a minimum, to a level commensurate with that which can be attained by a closed-cycle cooling system*.

(2). Track 2. If an existing power plant* owner or operator demonstrates to the Water Board's satisfaction that Track 1 is not feasible*, the power plant must reduce the level of adverse environmental impacts from the cooling water intake structure to a comparable level to that which would be achieved under Track 1, using operational or structural controls, or both. A reduction in environmental impacts under Track 2 will achieve a "comparable level" if both impingement mortality and entrainment of all life stages of marine life are reduced to 90 percent or greater of the reduction that would be achieved under Track 1, using closed cycle wet cooling.

B. Final Compliance Dates

(1). Existing non-nuclear fueled power plants having a capacity utilization rate of 20 percent or less shall comply with Section 2.A above no later than January 1, 2015.

(2). Existing non-nuclear-fueled power plants having a capacity utilization rate greater than 20 percent shall comply with Section 2.A above no later than January 1, 2018.

(3). Except as provided in D. below, existing nuclear-fueled power plants shall comply with Section 2.A above no later than January 1, 2021.

C. Interim Requirements

(1). No later than one year after the effective date of this Policy, existing power plants with offshore intakes shall install large organism exclusion devices having a mesh size no greater than 4" square. If the discharger opts to comply with this Policy using Track 2 controls, this measure will be allowed to count as an operational control to assist in meeting the required impingement reductions.

(2). During the interim period between the effective date of this Policy and the date for final compliance specified in Section 2.B above, existing power plants not generating electrical energy for a period of two or more consecutive days shall reduce discharge flows to less than ten percent of the permitted daily flow rate. If the discharger opts to comply with this Policy using Track 2 controls, this measure will be allowed to count as an operational control to assist in meeting the required impingement and entrainment reductions. This requirement shall be implemented in the NPDES permit for the power plant through an appropriate maximum intake flow limitation that applies during these periods.

(3). During the interim period between the effective date of this Policy and the date for final compliance specified in Section 2.B above, existing power plants must demonstrate that interim impingement and entrainment impacts due to the cooling water intake structure(s) are offset by habitat restoration efforts. A plan for habitat restoration must be included in the implementation plan (described in Section 3.B. below) submitted to the Water Board.

D. Nuclear-Fueled Power Plant Exception

If the owner or operator of an existing nuclear power plant demonstrates that compliance with the requirements for existing power plants* in Section 2.A. above of this Policy would result in a conflict with a safety requirement established by the Nuclear Regulatory Commission (Commission), with appropriate documentation or other substantiation from the Commission, the Water Board will make a site-specific determination of best technology available for minimizing adverse environmental impact that would not result in a conflict with the Commission's safety requirement.

3. Implementation

A. NPDES permits issued to regulate waste discharges from existing power plants to coastal or estuarine waters shall include requirements for cooling water intake structures that, at a minimum, implement the provisions of this policy.

B. Within one year of the effective date of this Policy, existing power plant dischargers shall submit an implementation plan for approval to the Water Board. The implementation plan shall identify the compliance alternative selected by the discharger, describe the design, construction, or operational measures that will be undertaken to implement the alternative, and propose a schedule for implementing these measures.

(1). If the discharger selects Track 1 as the compliance alternative, the discharger shall address in the implementation plan whether recycled water of suitable quality is available for use as makeup water.

(2). The Water Board shall promptly submit the implementation plan and proposed schedule to the Statewide Task Force for review. The Water Board shall request the Statewide Task Force to advise the Water Board on the discharger's proposed implementation schedule within six months of receipt of the discharger's proposed implementation schedule.

(3). The Water Board shall reissue or modify the permit to incorporate a final compliance schedule into the permit, after considering the advice from the Statewide Task Force. The final compliance schedule shall be incorporated into the permit no later than one year from the submittal of the discharger's implementation plan.

C. If a discharger selects Track 2 as the compliance alternative, the permit shall include a monitoring program that complies with Section 4 of this policy.

4. Track 2 Monitoring Provisions

A. Impingement Impacts

(1). A baseline impingement study shall be performed, unless the discharger demonstrates, to the Water Board's satisfaction, that prior studies accurately reflect current impacts. Baseline impingement shall be measured on-site and shall include sampling for all species impinged. The impingement study shall be designed to accurately characterize the species currently impinged and their seasonal abundance to the satisfaction of the Water Board.

(a). The study period shall be at least one year.
(b). Impingement shall be measured during different seasons when the cooling system is in operation and over 24-hour sampling periods.
(c). When applicable, impingement shall be sampled under differing representative operational conditions (e.g., differing levels of power production, heat treatments, etc.).

(2). After the Track 2 controls are implemented, to confirm the level of impingement controls, periodic impingement sampling, consistent with section (1) (a) to (c) above, shall be performed and reported to the Water Board.

(3). The need for new impingement studies shall be evaluated at the end of each permit period. Impingement studies shall be required when changing operational or environmental conditions indicate that new studies are needed.

B. Entrainment Impacts

(1). A baseline entrainment study shall be performed, unless the discharger demonstrates, to the Water Board's satisfaction, that prior studies accurately reflect current impacts. Baseline sampling shall be performed to determine larval composition and abundance in the source water (source water sampling) and entrained water (entrainment sampling). The source water shall be determined based on oceanographic conditions reasonably expected after Track 2 controls are implemented. Baseline entrainment sampling shall provide an unbiased estimate of larvae entrained at the intake prior to the implementation of Track 2 controls.

(2). Entrainment impacts shall be based on sampling for all ichthyoplankton* and zooplankton* (meroplankton*) species. Individuals collected shall be identified to the lowest taxonomical level practicable. When feasible*, genetic identification through molecular biological techniques may be used to assist in compliance with this requirement. Samples shall be preserved and archived such that genetic identification is possible at a later date.

(3). The study period shall be at least one year, and sampling shall be designed to account for variation in oceanographic conditions and larval abundance and behavior such that abundance estimates are reasonably accurate.

(4). After the Track 2 controls are implemented, to confirm the level of entrainment controls, periodic sampling shall be performed and reported to the Water Board.

(5). The need for new entrainment studies shall be evaluated at the end of each permit period. Entrainment studies shall be required when changing operational or environmental conditions indicate that new studies are needed.

5. Definition of Terms

Blowdown – the discharge of either boiler water or recirculating cooling water for the purpose of limiting the buildup of concentrations of materials in excess of desirable limits established by best engineering practice.

Capacity utilization rate – the ratio between the average annual net generation of power (in Megawatt-hours) and the total net capability of the facility to generate power (in Megawatts) multiplied by the number of hours during a year.

Closed Cycle Cooling System – a cooling water system, using either wet or dry cooling, from which there is no discharge of wastewater other than blowdown*.

Existing power plant – any power plant that is not a new* power plant.

Feasible – capable of being accomplished in a successful manner by the final compliance dates in this Policy, taking into account the following site-specific factors: availability of adequate space, potential impacts from increased noise on neighboring commercial or recreational land uses, air traffic safety, public safety, and the ability to obtain necessary permits, such as permits from the California Coastal Commission or local air district.

Ichthyoplankton – the planktonic early life stages of fish (i.e., the pelagic eggs and larval forms of fishes).

Meroplankton – pelagic larvae and eggs of benthic invertebrates.

New power plant – any plant that is a “new facility”, as defined in 40 C.F.R. §125.83 (revised as of July 1, 2007), and that is subject to Subpart I, Part 25 of the Code of Federal Regulations (revised as of July 1, 2007).

Once-through Cooling – a cooling water system in which there is no recirculation of the cooling water after its initial use.

Planktonic Organism – phytoplankton, zooplankton, and ichthyoplankton.

Proportional Mortality (PM) – the proportion of larvae killed from entrainment to the larvae in the source population.

Zooplankton - those planktonic invertebrates larger than 200 microns (including invertebrates that are planktonic for their entire life cycle, and the pelagic larvae and eggs of benthic invertebrates*).*

APPENDIX B – CALIFORNIA COASTAL FACILITIES WATER INTAKE STRUCTURES AND CONTROL TECHNOLOGIES

Facility name (Location)	Offshore Intakes	Current Technology	Shore Structures	Current Measures
Alamitos Generating Station (Long Beach)	none		All Intake water from shoreline on Los Cerritos Channel (Alamitos Bay)	Traveling screens
Contra Costa Power Plant (Antioch)	Offshore intakes from San Joaquin River Delta service part of the plant		Shore intakes from San Joaquin River Delta service part of the plant Variable Frequency Drive Pumps	Vertical traveling screen with 3/8 in mesh panels
Diablo Canyon Power Plant (Avila Beach)	none		Shoreline Intake within an-made embayment	Vertical traveling screen with 3/8 in mesh panels
El Segundo Generation Station (El Segundo) – Note: *Planned conversion of units 1 & 2 to CC with dry cooling*	Submerged ocean intake conduit 2000 ft from shore at 20 ft depth	Velocity cap	Onshore structure fed by offshore intake has four screen bays	Vertical traveling screen with 5/8 in mesh panels
Encina Power Station (Carlsbad) *Planned conversion of plant to CC with dry cooling.*	none		Shore water intake in Agua Hedionda lagoon	Traveling screen
Harbor Generating Station (Wilmington district, Los Angeles)	none		Shore water intake in LA Harbor	Vertical traveling screen with 5/8 in. by 3/8 in. mesh panels
Haynes Generating Station (Long Beach) *Unites 3&4 replaced with cc in 2005 using OTC, Units 1&2 replacement underway using OTC, no plans for units 5&6*	none		Shore intake on a forebay and canal from Alamitos Bay (Long Beach Marina)	Units 1, 2 & 8 stationary screens, Units 5 & 6 traveling screens.
Huntington Beach Generating Station (Huntington Beach)	Submerged ocean intake conduit 1500 ft from shore at 17 ft depth	Velocity cap	Onshore structure fed by offshore intake has four screen bays (one for each unit)	Stationary screen and traveling screen for each bay
Mandalay Generating Station (Oxnard)	none		Shore intake from Channel Islands Harbor via Edison Canal	Vertical slide screens
Morro Bay Power Plant (Morro Bay) Note: Proposed *re-powering with 2 combined cycle units and OTC*	none		Shoreline Intake within Morro Bay	No technologies Listed –.

Facility name (Location)	Offshore Intakes	Current Technology	Shore Structures	Current Measures
Moss Landing Power Plant (Moss Landing)	none		Intakes along shoreline of Moss Landing Harbor	Vertical traveling screen with 5/16 and 3/8 in mesh panels
			Units 1&2 re-powered in 2002 with Combine Cycle and OTC Restoration Project in Elkhorn Slough	
Ormond Beach Generating Station (Oxnard)	Submerged ocean intake conduit 1950 ft from shore at 35 ft depth	Velocity cap	Onshore structure fed by offshore intake, has four screen bays (one for each unit)	Vertical traveling screen with 5/8 in mesh panels
Pittsburg Power Plant (Pittsburg)			Surface Intake along Suisun Bay	Vertical traveling screen with 3/8 in mesh panels and variable speed drive pumps
			2 steam units with OTC and I unit with combined cycle & evaporative cooling tower	
Potrero Power Plant (San Francisco)	Re-power Processing ended 3/06.		Pending San Francisco Grid Study, plant expected to shut down around 12/08	
Redondo Beach Generating Station (Redondo Beach)	Units 5 & 6 Intake In King Harbor	Velocity Cap	Shore structures fed by within-harbor intakes	Four Traveling screens with 5/8-In. Wire mesh
	Units 7 & 8 Intakes at Mouth of King Harbor	Velocity Cap	Shore structures fed by within-harbor intakes	Four Traveling screens with 5/8-In. Wire mesh
San Onofre Nuclear Generating Station (San Clemente)	Two Submerged ocean intake conduits 3183 ft from shore at 32 ft depth	Velocity Caps	Shore structures fed by ocean intakes. Two sets of six vertical traveling screens fitted with 3/8-in. mesh panels	Additional vertical louvers in the forebay with fish elevators, return fish via pipeline 1900 ft from shore
			Since 1991, mitigation requirements include fish barrier devices (velocity cap and fish elevators above) and restoration of kelp forests and wetlands.	
Scattergood Generating Station (Los Angeles) *LADWP under consent decree to replace project- no plans yet to re-power or convert cooling system*	Submerged ocean intake conduit 1600 ft from shore at 15 ft depth	Velocity Cap	Shore structures fed by ocean intakes.	Vertical traveling screens with 3/8-in by 3/4-in mesh panels