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

Final Substitute Environmental Document

State Water Resources Control Board
California Environmental Protection Agency

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STATE WATER RESOURCES CONTROL BOARD
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§316(b)	*Section 316(b) of the federal Clean Water Act*
BACT	*Best Available Control Technology*
Basin Plan	*Regional Water Quality Control Plan*
BG	*Billion gallons*
BGD	*Billion gallons per day*
BPJ	*Best Professional Judgment*
BTA	*Best Technology Available*
BTU	*British Thermal Units*
CAISO	*California Independent System Operator*
Cal. Code Regs.	*California Code of Regulations*
Cal. Wat. Code	*California Water Code*
CDS	*Comprehensive Demonstration Study*
CEC	*California Energy Commission*
CEQA	*California Environmental Quality Act*
CFR.	*Code of Federal Regulations*
CPUC	*California Public Utilities Commission*
CUR	*Capacity Utilization Rate*
CWA	*Clean Water Act*
EIR	*Environmental Impact Report*
ELGs	*Effluent Limitation Guidelines*
ERP	*Expert Review Panel*
ETM	*Empirical Transport Model*
Ft/sec	*Feet per second*
GW	*Gigawatt*
GWh	*Gigawatt-hour*
HPF	*Habitat Production Foregone*
IAWG	*Inter-agency Working Group*

IM/E	*Impingement mortality and entrainment*
LADWP	*Los Angeles Department of Water and Power*
LAER	*Lowest Achievable Emissions Rate*
m^3	*Cubic meter*
MGD	*Million gallons per day*
MMBTU	*Million British Thermal Units*
MPA	*Marine Protected Areas*
MW	*Megawatt*
MWh	*Megawatt-hour*
NMFS	*National Marine Fisheries Service*
NOAA	*National Oceanic and Atmospheric Administration*
NPDES	*National Pollutant Discharge Elimination System*
NSPS	*New Source Performance Standards*
NSR	*New Source Review*
NRC	*Nuclear Regulatory Commission*
Ocean Plan	*California Ocean Plan*
OTC	*Once-Through Cooling*
PG&E	*Pacific Gas & Electric Company*
Porter-Cologne	*Porter-Cologne Water Quality Control Act*
PM	*Proportional Mortality*
PM10	*Particulate matter of 10 microns or less*
ppm	*Parts per million*
%	*Percent*
Regional Water Board	*Regional Water Quality Control Board*
SAT	*Marine Life Protection Act Science Advisory Team*
SED	*Substitute Environmental Document*
SIP	*Policy for Implementation of Toxics Standards for Inland Surface Waters, Enclosed Bays, and Estuaries of California*
State Water Board	*State Water Resources Control Board*
SONGS	*San Onofre Nuclear Generating Station*
Thermal Plan	*Water Quality Control Plan for Control of Temperature in the Coastal and Interstate Waters and Enclosed Bays and Estuaries of California*
Tit.	*Title*
U.S.C.	*United States Code*
USEPA	*United States Environmental Protection Agency*
Water Boards	*State and Regional Water Boards*

1.0 INTRODUCTION

1.1 PURPOSE

This report represents the State Water Resources Control Board(State Water Board)'s formal water quality planning and Substitute Environmental Document (SED) for the adoption of technology-based standards that will address the adverse effects associated with cooling water withdrawals from the State's coastal and estuarine waters. This policy, entitled *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling* ("Policy"), applies to the State's thermal power plants that currently withdraw water from the State's navigable waters using a single-pass system, also known as once-through cooling (OTC).

OTC can cause adverse impacts when aquatic organisms are trapped against a facility's intake screens (impinged) and cannot escape, or when they suffer contact injuries that increase mortality. Likewise, smaller organisms, such as larvae and eggs, can be drawn through a facility's entire cooling system (entrained) and subjected to rapid pressure changes, chemical treatment systems, and violent sheering forces, only to be discharged along with the now-heated cooling water and other facility wastewaters.

The State's active coastal power plants that use OTC maintain the capacity to withdraw more than 15 billion gallons per day (BGD) of cooling water. Over the course of a year, billions of eggs and larvae are effectively removed from coastal waters, while millions of adult fish are lost due to impingement. These OTC systems, many of which have been in operation for 30 years or more, present a considerable and chronic stressor to the State's coastal aquatic ecosystems by reducing important fisheries and contributing to the overall degradation of the State's marine and estuarine environments.

The Policy adopts appropriate technology-based standards that will significantly reduce these adverse impacts and implements a statewide process by which this goal can be achieved without disrupting the critical needs of the State's electrical generation and transmission system. This approach further reduces the permitting burden on the Regional Water Quality Control Boards (Regional Water Boards) by coordinating implementation at the state level.

1.2 NEED FOR PROPOSED POLICY

The federal Clean Water Act (CWA) addresses OTC's adverse impacts in Section 316(b) (§316(b)), which mandates technology-based measures to minimize adverse environmental impacts from cooling water intake structures (CWIS). As the agency authorized to implement §316(b)'s requirements, the US Environmental Protection Agency (USEPA) has made repeated efforts to develop national regulations that would establish uniform performance standards for facilities that use cooling water. These standards would be implemented through National Pollution Discharge Elimination System (NPDES) permits.

USEPA's first attempt at a national rule, in 1977, was withdrawn following a successful lawsuit by industrial petitioners. Later efforts divided power plants into two categories—new and existing—based on the presumption that facilities defined as "new"[1] might have more technology options available to them for compliance since any control technology could be incorporated into the facility's initial design. In 2001 USEPA adopted the Phase I rule for new facilities that established a performance standard based on closed-cycle wet cooling. The

[1] 40 CFR. §125.81.

Phase I rule remains the primary governing regulation for new power plants nationwide, including California.[2]

USEPA adopted the Phase II rule in 2004 to address existing power plants with intake capacities larger than 50 million gallons per day (MGD). Litigation following the rule's adoption, however, ultimately led USEPA to suspend Phase II in 2007 with no clear indication when, or if, a revised rule would be issued. USEPA directed NPDES permitting authorities to implement §316(b)'s requirements for existing facilities using best professional judgment (BPJ), the same guidance that has been in place since 1977.

The BPJ approach for §316(b) has been used by the various Regional Water Boards when re-issuing NPDES permits for power plants within their jurisdiction. The effectiveness of this approach, however, has been mixed. The question of how to address these impacts is complex and requires significant resources to evaluate the intertwined technical and biological issues that comprise a BPJ analysis. Sufficient resources may not be available to each Regional Water Board, which can lead to varying decision criteria and different conclusions regarding the most appropriate technology-based solution. Some of these NPDES permits, absent a firm policy standard which to base requirements on, have been challenged repeatedly by industrial and citizen petitioners, resulting in lengthy administrative extensions well beyond their original expiration dates. Still other permits were delayed when it appeared likely USEPA would adopt a sustainable Phase II rule. The result is a significant backlog in reissuing most of the State's NPDES permits for the coastal facilities (see Table 1, below).

This Policy is needed to address an ongoing, critical impact to the State's waters that remains unaddressed at the national level for existing facilities despite §316(b)'s enactment more than 35 years ago; additional action by USEPA on this issue remains unclear. Furthermore, a concise, statewide policy addresses the statute's inconsistent application among the Regional Water Boards and lessens the considerable resource burden associated with the BPJ process.

1.3 FEDERAL AND STATE LEGAL AND REGULATORY BACKGROUND

1.3.1 *Clean Water Act §316(b)*

CWA §316(b) requires

> Any standard established pursuant to §§ 301 or 306 of this Act and applicable to a point source shall require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact.

Thus, a permitted facility with a cooling water intake structure must comply with the *technology-based* standard for minimizing impingement and entrainment impacts.[3]

In April 1976, USEPA issued a final rule implementing §316(b)[4] but was sued by a group of utility companies that successfully challenged the rule on procedural grounds. USEPA withdrew the relevant portions of the rule in 1977, but directed NPDES permitting authorities to

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[2] The Porter-Cologne Act also establishes a narrative standard for "new and expanded" coastal facilities that use seawater for industrial processes.
[3] 33 U.S.C. §1326(b).
[4] 41 Fed. Reg. 17387 (April 26, 1976).

Table 1. NPDES Permit Status for OTC Facilities

Region	Facility	Permittee	NPDES Permit Adoption Date	NPDES Permit Expiration Date	Permit in Review?	Notes
1	Humboldt Bay Power Plant	PG&E	26-Apr-01	26-Apr-06	Yes	Has filed to re-power with dry cooling
2	Pittsburg Power Plant	Mirant Delta, LLC	19-Jun-02	31-May-07	Yes	
2	Potrero Power Plant	Mirant Potrero, LLC	10-May-06	31-Dec-08	No	
3	Diablo Canyon Power Plant	PG&E	11-May-90	11-May-95	Yes	
3	Morro Bay Power Plant	Dynegy	10-Mar-95	10-Mar-00	Yes	
3	Moss Landing Power Plant	Dynegy	27-Oct-00	27-Oct-05	Yes	
4	Alamitos Generating Station	AES Alamitos, LLC	29-Jun-00	10-May-05	Yes	
4	El Segundo Generating Station	NRG West	29-Jun-00	10-May-05	Yes	Has filed to repower with dry cooling for Units 1&2
4	Harbor Generating Station	LADWP	10-Jul-03	10-Jun-08	No	
4	Haynes Generating Station	LADWP	29-Jun-00	10-May-05	Yes	
4	Mandalay Generating Station	RRI Energy Mandalay LLC	26-Apr-01	10-Mar-06	Yes	
4	Ormond Beach Generating Station	RRI Energy Mandalay LLC	28-Jun-01	10-May-06	Yes	
4	Redondo Generating Station	AES Redondo Beach LLC	29-Jun-00	10-May-05	Yes	
4	Scattergood Generating Station	LADWP	29-Jun-00	10-May-05	Yes	
5S	Contra Costa Power Plant	Mirant Delta, LLC	27-Apr-01	1-Apr-06	Yes	
8	Huntington Beach Generating Station	AES Huntington Beach, LLC	14-Oct-06	1-Aug-11	No	
9	Encina Power Plant	NRG West	16-Aug-06	1-Oct-11	No	
9	SONGS Unit 2	Southern California Edison	11-May-05	11-May-10	No	
9	SONGS Unit 3	Southern California Edison	11-May-05	11-May-10	No	
9	South Bay Power Plant	Dynegy	10-Nov-04	10-Nov-09	No	

Notes:
PG&E: Pacific Gas & Electric Company
LADWP: Los Angeles Department of Water and Power
SONGS: San Onofre Nuclear Generating Station

continue implementing §316(b) on a case-by-case basis pursuant to CWA §402(a)(1)(B) using BPJ.[5]

In 1993 a group of environmental organizations, led by Hudson Riverkeeper, filed suit against USEPA, claiming its failure to establish national technology-based standards violated the CWA.[6] In the plaintiff's view, the case-by-case, site-specific approach created an inconsistent application of the CWA by ignoring the mandate to minimize adverse impacts to a level based on what could be achieved by the best performing technology. The site-specific, BPJ approach too often resulted in "technology-based" assessments evaluated against population or water quality-based impacts. In 1995, USEPA entered into a consent decree with Riverkeeper and other environmental plaintiffs that established a framework to develop and promulgate national technology-based standards that would implement §316(b). Subsequent amendments to the consent decree established a phased approach for implementation, separating new facilities from existing ones.

1.3.2 *Phase I Rule*

USEPA adopted the Phase I rule for new facilities on November 9, 2001.[7] The Phase I rule applies to new electric generating plants and manufacturers that withdraw more than 2 MGD from waters of the U.S. and use 25 percent (%) or more of their intake water for cooling.[8] New facilities with smaller cooling water intakes continue to be regulated on a site-by-site basis.[9]

The Phase I rule is based on USEPA's determination that, for new facilities, the §316(b) best technology available (BTA) performance standard is achieved by reducing the facility's intake flow to a level commensurate with a closed-cycle wet cooling system, and reducing the through screen intake velocity to 0.5 foot per second (ft/sec) or less. Notably, Phase I does not require a facility to adopt closed-cycle cooling in order to comply but instead contains a two track approach that acknowledges the ability of different technology options to achieve reductions that are substantially similar to closed-cycle wet cooling. The decision to follow Track 1 or Track 2 is left to the facility.

Track 1 allows a facility to demonstrate its compliance with the BTA standard by implementing specific flow-reduction technologies and/or operational measures.[10] USEPA adopted the Track 1 approach as a "fast track" compliance method for new facilities in recognition of industry trends that were already moving towards closed-cycle cooling as a preferred technology. The relative certainty with which flow and velocity reduction measures can achieve acceptable impingement and entrainment levels enables the Track 1 facility to forgo extensive background monitoring requirements prior to initial construction, and no initial approval of its cooling system design is required.[11]

Track 2, the "demonstration track," allows a new facility to use any combination of design measures, technologies, and operating methods to reduce adverse environmental impact to a level comparable to that which would be achieved under Track 1, thus demonstrating

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[5] 33 U.S.C. §1342(a)(1)(B).
[6] See *Cronin v. Browner* (S.D.N.Y. 1995) 898 F.Supp. 1052.
[7] 66 Fed. Reg. 65338 (December 18, 2001), codified at 40 CFR. pt. 125, subpt. I.
[8] 40 CFR. §125.81.
[9] *Id.* §125.80(c).
[10] Track 1 distinguishes between facilities withdrawing between 2 and 10 MGD, and those withdrawing more than 10 MGD. None of California's coastal OTC facilities falls into the lesser category; therefore, the discussion of Track 1 in the Policy refers only to requirements for facilities 10 MGD or greater.
[11] *40 CFR* §125.86(b)(4)

compliance with the BTA standard.[12] USEPA defines "comparable level" in this instance as reductions of "both impingement mortality and entrainment of all life stages of fish and shellfish to 90% or greater" of the Track 1 reduction.[13] The initial permitting for Track 2 is generally thought to be a more lengthy and involved process by requiring the facility to conduct a comprehensive demonstration study (CDS) that must be submitted to the permitting authority along with the NPDES application. The CDS must contain an evaluation of the different technology measures that the facility proposes to use as well as a source water biological characterization and a verification monitoring plant the will demonstrate continued compliance, subject to the approval of the permitting authority.[14] Track 2 permitted restoration to be used as a compliance technology.

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.[15] 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.

The Phase I rule, as proposed, allowed restoration to be used as a "technology" for compliance under Track 2. Following a legal challenge by both industrial and environmental petitioners, the Second Circuit Court of Appeals remanded those aspects of the rule that permitted restoration, noting that restoration conflicted with CWA §316(b)'s requirement to minimize impacts rather than compensate for those impacts after they have occurred.[16] Additional challenges to Phase I were unsuccessful.

1.3.3 *Phase II Rule*

On July 23, 2004, USEPA adopted intake regulations for large existing power plants (Phase II).[17] The Phase II rule applied to existing electric generating plants that are designed to withdraw at least 50 MGD and use at least 25% of their withdrawn water for cooling purposes.[18]

In the Phase II rule, USEPA did not base the performance standards on closed-cycle wet cooling, opting instead to use a range of technologies that it determined to be "commercially available for the industries affected as a whole" but still capable of achieving acceptable impingement mortality and entrainment reductions.[19] Closed-cycle wet cooling was not considered for Phase II because, in USEPA's determination, it was not the most "cost-effective" when considering the benefits that could be achieved by other technologies. The considerations for adopting closed-cycle cooling at an existing facility were believed to be fundamentally different from a new facility, which had the advantages of incorporating such changes into their initial designs without incurring performance penalties that triggered further compliance costs.[20]

Using the "suite of technologies" approach, USEPA established the Phase II impingement mortality performance standard at 80-95% below the baseline calculation, while similarly

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[12] *Id.* §125.84(d)(1).
[13] 66 FR 65318 (No. 243)
[14] *40 CFR* §125.84(d)(1).
[15] *Id.* §125.85.
[16] Riverkeeper, Inc. v. USEPA (2d Cir. 2004) 358 F.3d 174 ("Riverkeeper I")
[17] 69 Fed. Reg. 41683
[18] See 40 CFR. §125.91.
[19] 69 FR 41683 (No. 131)
[20] 69 FR 41605 (No. 131)

requiring an entrainment reduction to 60-90% below baseline.[21] Baseline values are defined as impingement mortality and entrainment (IM/E) that would occur at the facility absent any controls or modifications specifically designed to reduce such impacts. Under Phase II, the baseline design was considered to be a once-through system with standard intake screens (3/8 inch mesh) located parallel to the shoreline at the surface of the intake water body. A facility could alternatively propose a modified baseline calculation if it could demonstrate that its intake system, by incorporating different design elements or technologies, was already achieving IM/E reductions, whether in whole or in part.[22]

The Phase II rule allowed facilities to demonstrate BTA using one of five compliance alternatives, the first of which allowed a facility to demonstrate it had reduce its intake flow to a level commensurate with a closed-cycle wet system and its intake velocity to no more than 0.5 ft/sec, thereby exempting the facility from further compliance requirements. Three additional alternatives were varied approaches by which the facility could demonstrate it would achieve the performance standards described above, while the final alternative allowed a site-specific BTA determination that would be evaluated using one of two tests. Site-specific determinations could be based on either a “cost-cost” test, wherein a facility could show the actual compliance costs would be significantly greater than the costs USEPA considered in developing the Phase II rule, or a “cost-benefit” test, in which compliance costs were shown to be “significantly greater” than the benefits of meeting the performance standards. [23] Except for the first alternative, compliance could be achieved with any combination of design and construction technologies, operational measures, or restoration measures.

Following legal challenges by environmental and industrial petitioners, the Second Circuit Court of Appeals issued its ruling on the Phase II rule on January 25, 2007.[24] The *Riverkeeper II* decision remanded several significant provisions of the Phase II rule to USEPA for further clarification while remanding other portions as “impermissible constructions of the statute.”[25] 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.

Among *Riverkeeper II*’s key findings:

- BTA cannot be interpreted as “best technology available commercially at an economically practicable cost,” as USEPA had done in Phase II, because the statute does not expressly authorize cost tests. Costs may be considered, however, 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, e.g., selecting between two technologies that achieve substantially similar performance but at disproportionate costs.

- The cost-benefit compliance alternative is impermissible because the statute does not authorize a site-specific BTA determination using a cost-benefit analysis. The court restated its conclusion in *Riverkeeper I* that the CWA does not permit USEPA to consider water quality, i.e. wildlife levels in the water body, in making BTA determinations.

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[21] *Id.* §125.94(b)(1) and (2).
[22] 40 CFR § 125.93
[23] *Id.* §125.94(a)(5).
[24] ***See*** Riverkeeper, Inc. et al. v. U.S. Environmental Protection Agency, (2nd Cir, January 25, 2007) 475 F.3d 83. (“Riverkeeper II”)
[25] *Id.*

- BTA must be based on the optimally best performing technology rather than the average performance at multiple facilities.

- Restoration provisions are plainly inconsistent with the statute and impermissible in the Phase II rule.

In response to the Second Circuit's ruling, USEPA suspended the Phase II rule on March 20, 2007 and directed permitting authorities to use BPJ to implement §316(b) requirements.[26] Industry groups appealed to the US Supreme Court, which agreed to review only the narrow questions of whether USEPA permissibly relied upon on a cost-benefit test to develop the Phase II performance standards or, by extension, could allow for a site-specific variance that also relied on cost-benefit.

The US Supreme Court issued its ruling (*Entergy Corp. v. Riverkeeper, Inc. et. al. (2009) 556 U.S. [129 S.Ct. 1498])* on April 1, 2009. The majority opinion effectively reversed the Second Circuit's ruling by agreeing with USEPA's contention that a cost-benefit test, while not expressly authorized in the §316(b) statute, is not prohibited either. USEPA may, at its discretion, act using its own interpretation of a silent or ambiguous statute provided that interpretation can be considered reasonable; it is not necessary for the courts to agree that the interpretation is the *most* reasonable.[27] Notably, the *Entergy* decision does not require USEPA to consider a cost-benefit approach in any future §316(b) rulemaking effort, including a revised Phase II rule.

1.3.4 *Porter-Cologne*

The Porter-Cologne Water Quality Control Act (Porter-Cologne)[28], 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 Board. The State Legislature, in adopting Porter-Cologne, directed that the State's waters "shall be regulated to attain the highest water quality which is reasonable[.]"[29]

The State Water Board oversees and guides the Regional Water Boards through several activities, including the adoption of statewide water quality control plans[30] and state policies for water quality control[31]. 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 (including industrial water supply), and establishes water quality objectives to protect beneficial uses.[32] The State Water Board is also charged with adopting state policies for water quality control, which may consist of principles or guidelines deemed essential by the State Water Board for water quality control.[33]

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[26] As of the publication of this study, USEPA has not formally withdrawn the Phase II rule, noting that future litigation may be possible.
[27] ***See*** Chevron USA, Inc. v. Natural Resources Defense Council, Inc. (1984) 467 US 837.
[28] Wat. Code §13000 et seq.
[29] See *id*.
[30] See *id.* §13170.
[31] See *id.* §13140 et seq.
[32] California Ocean Plan (2005), chs. 1 & 2.
[33] Wat. Code §13142.

Under Porter-Cologne, the State and Regional Water Boards regulate waste discharges that could affect water quality through waste discharge requirements.[34] 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 CWA.[35] To ensure consistency with CWA requirements, Porter-Cologne requires that the Water Boards issue and administer NPDES permits such that all applicable CWA requirements are met.[36] The State Water Board is designated as the state water pollution control agency under the CWA and is authorized to exercise any powers accordingly delegated to the State.[37,38]

In one section, Porter-Cologne contains a provision addressing coastal facilities that withdraw water for industrial purposes, although the provision only applies to "new or expanded facilities." California Water Code (Cal Wat. Code) §13142.5(b) requires each new or expanded coastal power plant or other industrial installation using seawater for cooling, heating or industrial processing to use "the best available site, design, technology, and mitigation measures feasible . . . to minimize the intake and mortality of all forms of marine life."

Prior to this Policy, the State Water Board had not adopted any state policies or water quality control plans to implement §316(b) or Cal Wat. 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. That policy, in Resolution No. 75-58 ("Water Quality Control Policy on the Use and Disposal of Inland Waters Used for Power Plant Cooling"),[39] was intended to discourage the use of inland water resources for once-through cooling by favoring the use of treated wastewater or seawater for cooling in order to conserve diminishing fresh water sources for other uses. The 1975 policy does not explicitly address §316(b)-related impacts from cooling water systems and is out of date even with respect to the State's increasing demands on all water resources, fresh or marine.

1.3.5 *Current Status*

The Phase I rule remains the governing regulation for all new facilities subject to §316(b). As stated previously, USEPA suspended the Phase II rule after the *Riverkeeper II* decision and, as of the Policy's adoption, has not declared its intent to revise or reissue a comparable regulation. 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 §316(b) requirements on a case-by-case basis.

For existing facilities, this is essentially the same regulatory environment that has persisted since the CWA was adopted in 1972. The absence of a uniform BTA standard, or at least a definitive process by which BTA determinations can be made, inhibits permitting authorities' ability to implement §316(b) consistently from site to site. As part of the withdrawn 1977 rule, USEPA did issue a draft guidance document that describes recommended studies for evaluating the impacts and recommends a process for determining BTA.[40] This document,

[34] See *id.* §§13263, 13377.
[35] Wat. Code, div. 7, ch. 5.5.
[36] *Id.* §13377; see also Cal. Code Regs., tit. 23, §2235.2.
[37] *Id.* §13160.
[38] *Id.* §§13372, 13377. USEPA's permit regulations are contained in 40 CFR. parts 122, 123, and 124.
[39] State Water Board Resolution No. 75-58.
[40] 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).

however, is outdated and does not capture the significant advances that have been made in cooling water intake technologies. Likewise, several USEPA General Counsel opinions from the 1970's address interpretation of §316(b).[41] None of these administrative documents is binding on the states, however.

Recent state and federal court decisions, however, provide some guidance as to what may or may not be considered when implementing §316(b) for existing facilities. The *Riverkeeper I* decision affirmed USEPA's BTA decision basis and implementation approach for Phase I, notably excepting any role for restoration in achieving compliance as a direct contravention of the statute. The Second Circuit reiterated that conclusion in *Riverkeeper II* and also remanded portions of the Phase II rule that expressed BTA as performance ranges rather than mandating the best achievable performance within that range.

The *Riverkeeper I* and *II* decisions affirmed USEPA's approach to determining what constitutes adverse environmental impact in both the Phase I and Phase II rules. Following its own ecological risk assessment guidelines, USEPA concluded that it is reasonable to interpret adverse environmental impact as "including impingement and entrainment, diminishment of compensatory reserves, stresses to the population or ecosystem, harm to threatened or endangered species, and impairment of State…water quality standards"[42] and should be minimized to the maximum extent practicable. Industry petitioners had argued that any impacts must be shown to have deleterious effects on the overall fish and shellfish populations influenced by the intake before it can be considered adverse environmental impact and thus subject to additional regulation. The Second Circuit rejected this argument, recognizing USEPA's approach was reasonable in light of Congress' inclusion of a technology-based approach in §316(b), whereas any consideration of population effects would transform the statute to a water-quality-based measure.

The *Entergy* decision is significant in that it affirmed the use of a cost-benefit analysis as a reasonable approach that *may* be used to determine best technology available. The Court explicitly noted, however, that USEPA was not *required* to use this method under the statute and could have presumably issued a Phase II rule that did not rely so heavily on cost-benefit. Nor did the Court rule on the specifics of how such a cost-benefit approach was to be used, e.g., how are benefits meant to be monetized and what threshold test should be used, although members did express concern over the ambiguity in the term "significantly greater" and how it differed from the wholly disproportionate approach.

A recent court proceeding involving the Central Coast Regional Water Board's BPJ-based permit for the Moss Landing Power Plant may also be instructive as to how cost-benefit test may be incorporated into the Policy. The proposed permit authorized the facility to use once-through cooling for two new combined-cycle power-generating units that would be constructed to replace other units slated for retirement. Relying on decision law interpreting §316(b) on a case-by-case basis, the Central Coast Regional Water Board had determined that the costs of other technologies, including closed-cycle wet cooling, were wholly disproportionate to the environmental benefits that could be gained.

A non-profit advocacy organization, Voices of the Wetlands, challenged the permit's basis, claiming the Central Coast Regional Water Board had improperly relied on the environmental

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[41] See, e.g., Op. USEPA 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. USEPA Gen. Counsel 63 (July 29, 1977).
[42] 66 FR 65292 (No. 243)

enhancement plan as a substitute for selecting BTA and had improperly applied the wholly disproportionate test without a clear definition or formula.[43] The appellate court, however, upheld the district court's finding that the Central Coast Regional Water Board did not improperly use the environmental enhancement plan in lieu of technology to implement §316(b). Instead the court held that the enhancement plan served as the basis for monetizing benefits that could then be compared to costs using the cost-benefit test. Furthermore, both the district and appellate courts[44] upheld the wholly disproportionate method as applied in this case, stating the analysis had "considered such factors as the magnitude of the impact, the degree to which it reasonably could be minimized, and the proportionality of the cost of doing so," all of which were proper under the BPJ standard.[45]

1.3.6 *CEQA Analysis and Impact of Proposed Policy*

The State Water Board is the lead agency for this project under the California Environmental Quality Act, or CEQA,[46] and is responsible for preparing environmental documentation for the proposed Policy. The California Secretary of Resources has certified the State Water Board's water quality planning process as exempt from certain CEQA requirements, including the requirements to prepare Environmental Impact Reports (EIRs), Negative Declarations, and Initial Studies.[47] Instead, the State Water Board must fulfill the requirements of its "certified regulatory program" regulations when adopting plans, policies, and guidelines.

Despite this limited exemption, the State Water Board must still comply with CEQA's overall objectives, which are to: 1) inform the decision makers and public about the potential significant environmental effects of a proposed project; 2) identify ways that environmental damage may be mitigated; 3) prevent significant, avoidable damage to the environment by requiring changes in projects, through the use of alternative or mitigation measures when feasible; and 4) disclose to the public why an agency approved a project if significant effects are involved.[48]

State Water Board regulations (Title 23, Cal. Code of Reg. Chapter 27, §3777) require that a document prepared under its certified regulatory program must include:

- A brief description of the proposed project;
- Reasonable alternatives to the proposed project; and
- Mitigation measures to minimize any significant adverse environmental impacts of the proposed activity.

Accordingly, the State Water Board prepares programmatic "Substitute Environmental Documents" (SEDs) in lieu of EIRs or other environmental documents when proposing statewide water quality objectives and programs of implementation. This document fulfills the requirements of a SED. Until recently, the State Water Board referred to these formal planning documents as "Functional Equivalent Documents", although there is no substantive difference between them. Responses to public comments and consequent revisions to the information in the Draft SED are subsequently presented in a Draft Final SED for consideration by the State Water Board. After the State Water Board has certified the document as adequate, the document is re-titled as the Final SED.

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[43] Voices of Wetlands v. California State Water Resources Control Bd. (2007) 157 Cal. App. 4th 126869 Cal.Rptr.3d 487
[44] The California Supreme Court granted a petition for review of the appellate decision on March 18, 2008. 74 Cal.Rptr 3d 453.
[45] *Id.* at 45.
[46] Public Resources Code, §21000 *et seq*.
[47] Cal. Code Regs, tit. 14, §15251(g); see Public Resources Code, §21080.5.
[48] Cal. Code Regs., tit. 14, § 15002(a).

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.

1.3.7 *Compliance with Cal. Wat. Code §§ 13241 and 13242*

In addition to the factors assessed under CEQA, Cal. Wat. Code §13241 requires the assessment of specific factors when the State or Regional Water Boards establish water quality objectives to ensure the reasonable protection of beneficial uses. Factors to be considered by the State or Regional Board in establishing water quality objectives include:

- Past, present, and probable future beneficial uses of water.
- Environmental characteristics of the hydrographic unit under consideration.
- Water quality conditions that could reasonably be achieved through control of all factors affecting water quality.
- Economic considerations.
- The need for developing housing within the region.
- The need to develop and use recycled water.

Cal. Wat. Code §13242 requires the Water Boards to formulate a program of implementation for the water quality objective under consideration by the Board. The program of implementation for achieving water quality objectives shall include, but not be limited to:

- A description of the nature of actions that is necessary to achieve the objectives, including recommendations for appropriate action by any entity, public or private.

- A time schedule for the actions to be taken.

- A description of surveillance to be undertaken to determine compliance with objectives.

1.4 PUBLIC PROCESS

Public involvement in the policy development process began on September 26, 2005 when the State Water Board held a public workshop in Laguna Beach to solicit comments and information as to whether the State Water Board should adopt a statewide policy implementing §316(b). An additional workshop was held in Oakland on December 7, 2005. Following the input received at these meetings, the State Water Board released its scoping document, *Proposed Statewide Policy on Clean Water Act §316(b) Regulations*, on June 13, 2006.[49] A public scoping meeting

[49] The scoping document is intended to provide the public with a preliminary proposal for a state policy and outline the different issues that will be considered when developing the final policy. Scoping meetings are held, and public comments accepted, to address public questions and identify additional areas that need to be addressed in the final policy.

was held on July 31, 2006 in Sacramento during which the State Water Board accepted written and oral comments on the scoping document.

Following USEPA's suspension of the Phase II rule, the State Water Board revised the proposed policy to incorporate regulatory changes directed by the *Riverkeeper II* decision and released an updated scoping document on March 18, 2008. Additional public scoping meetings were held on May 8, 2008 in San Pedro and May 13, 2008 in Sacramento. The State Water Board solicited comments on the revised scoping document from all interested parties no later than May 20, 2008.[50]

In addition to the public scoping meetings, the State Water Board, in conjunction with other state agencies, sponsored a research results symposium, *Understanding the Environmental Effects of Once-Through Cooling,* on January 15th and 16th at the University of California, Davis. The symposium gathered experts with extensive experience researching the many issues associated with power plant cooling to present findings from current research into areas such as engineering trends, compliance methods, and transmission system reliability. Presentations from the symposium can be found at the State Water Board's web site at http://www.waterboards.ca.gov/water_issues/programs/npdes/cwa316.shtml .

The State Water Board posted the Draft Policy on its web site (see above) on June 30, 2009 and the supporting Draft SED on July 15, 2009 for public comment. Written public comments were due on September 30, 2009. The State Water Board conducted an informal workshop in Sacramento on September 8, 2009 to discuss the Draft Policy and answer questions. A public Hearing on the proposed Policy was held in Sacramento on September 16, 2009.

State Water Board staff made revisions to the proposed Policy based on the comments received from the public and State Water Board Members, and posted the revised Draft Policy on its web site on November 23, 2009. On December 1, 2009, the State Water Board held a public Workshop in Sacramento to receive comments on the proposed revisions to the Draft Policy. At the workshop, the State Water Board extended the deadline for the public to submit comments on Policy revisions to December 8, 2009. State Water Board staff has responded to comments received from the public and made revisions to the revised Draft Policy and Draft SED as appropriate. Staff's responses to written public comments are shown in Appendix G of this document. All public documents have been posted on the State Water Board's web site at http://www.waterboards.ca.gov/water_issues/programs/npdes/cwa316.shtml.

1.5 ADVISORY AND SCIENTIFIC REVIEW PANELS

1.5.1 *Expert Review Panel*

At its April 20, 2006 meeting, the Ocean Protection Council adopted a "Resolution of the California Ocean Protection Council Regarding the Use of Once-Through Cooling Technologies in Coastal Waters." In that resolution, the Ocean Protection Council 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)."

[50] *Id.*

The State Water Board recognizes that adverse impacts associated with OTC are often difficult to accurately quantify, particularly with regard to entrainment. The complexity of these issues underscores the need to seek input from technical experts in multiple disciplines, including ecological modeling, coastal marine biology, physical oceanographic processes, and engineering. The State Water Board, therefore, contracted with Moss Landing Marine Laboratory to convene an Expert Review Panel (ERP) to review the scoping document and the proposed policy. Staff, in conjunction with the ERP, developed a set of questions relative to the draft policy that the ERP would then seek to answer.

The ERP membership comprised academic and consulting scientists as well as technical experts representing industry and the environmental community. Under the direction of Dr. Michael Foster, the ERP included:

- Dr. Gregor Caillet, Moss Landing Marine Laboratories
- Dr. Pete Raimondi, Professor and Chair, Department of Biology. University of California, Santa Cruz.
- David Bailey, Sr. Project Manager, EPRI
- Tim Hemig, Director, Environmental & New Business, NRG Energy
- Sarah Abramson, Director of Coastal Resources, Heal the Bay
- John Steinbeck, Vice President and Principal Scientist, Tenera Environmental

Questions presented to the ERP addressed the current state of impacts, proposed compliance options, and interim measures. The full text of each question and the ERP's summary response are presented in Appendix B. Individual responses from each member are located at http://www.waterboards.ca.gov/water_issues/programs/npdes/cwa316.shtml.

1.5.2 *Interagency Working Group*

The Interagency Working Group (IAWG) is an informal committee composed of staff from agencies that have a compelling interest in the State Water Board's policy development process. Depending on how facilities choose to comply with the Policy, secondary impacts may result that could affect the facility's air emissions or its status as a generator on the State's electrical grid. The State Water Board convened the IAWG so it could adequately address other state agency concerns prior to finalizing the policy. The IAWG consists of staff members from the State Water Board, California Air Resources Board, California Independent Systems Operator (CAISO), State Lands Commission, California Coastal Commission, California Public Utilities Commission (CPUC) and the California Energy Commission (CEC). The implementation schedule in the proposed Policy was developed with input from the IAWG. As part of that process, the energy agencies (CEC, CPUC, and CAISO) proposed their recommended implementation schedule (see Appendix C).

1.6 PROPOSED PROJECT AND DESCRIPTION

The State Water Board is proposing the following project: the adoption of the *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling* (as shown in Appendix A). The Policy contains technology-based performance standards to address adverse impacts from OTC systems and an implementation plan that addresses potential effects to the State's electrical transmission system while simultaneously coordinating the efforts of the State and Regional Water Boards.

Subject facilities may demonstrate compliance with the Policy's performance standards using one of two alternatives. Track 1 achieves IM/E reductions by requiring minimum flow and intake velocity reduction levels, but exempts the facility from conducting significant future monitoring to verify compliance. Track 2 establishes minimum IM/E reductions compared to a calculation baseline that can be achieved with a combination of technologies and operational measures. The facility must also implement an ongoing verification monitoring plan if complying by other means than reduced velocity and flow. Technology-based improvements that are specifically designed to reduce impingement mortality and/or entrainment and were implemented prior to the effective date of the Policy may be counted towards meeting Track 2 requirements. Reductions in impingement mortality and entrainment resulting from prior replacement of steam turbine power-generating units with combined-cycle power-generating units[51] may also be counted towards meeting Track 2 requirements.

The Policy allows for alternative requirements for nuclear facilities in the event compliance with Track 1 or Track 2 would conflict with Nuclear Regulatory Commission (NRC) safety requirements. The owners/operators of nuclear-fueled power plants are also directed to fund independent, third-party studies that would analyze in detail the compliance options available to them, including costs and feasibility. An oversight committee will review the studies and report to the State Water Board at which time the State Water Board will address the need, if any, to modify the Policy.

The Policy, if adopted, would apply to all existing power plants that currently operate OTC systems. These 19 facilities[52] are located in coastal areas and estuaries extending from Humboldt Bay to San Diego Bay. Enforcement would be a joint effort between the State Water Board and Regional Water Boards for the North Coast (Region 1), San Francisco Bay (Region 2), Central Coast (Region 3), Los Angeles (Region 4), Central Valley-Sacramento (Region 5S), Santa Ana (Region 8) and San Diego (Region 9).

The Policy also establishes an advisory committee comprising staff from the State’s energy and environmental agencies to assist the State Water Board in reviewing implementation plans and schedules, and prevent disruptions to the State’s electrical supply. The committee will also advise the State Water Board as to the need, if any, to reopen the Policy for revision based on its findings.

1.7 STATEMENT OF GOALS

CWA §316(b) establishes a technology-based requirement to minimize the adverse environmental impacts from cooling water intake structures. The Policy, if adopted, will establish a uniform regulatory approach that will further Porter-Cologne’s mandate to attain the highest reasonable water quality possible for the use and enjoyment of the people of the state.

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[51] Refers to several units within a power plant which combined generate electricity through a two-stage process involving combustion and steam. Hot exhaust gas from one or two combustion turbines is passed through a heat recovery steam generator to produce steam for a steam turbine. The turbine exhaust steam is condensed in the cooling system and may or may not be returned to the power cycle. Combined-cycle power-generating units* are generally more fuel-efficient and use less cooling water than steam boiler units with the same generating capacity.

[52] Humboldt Bay Power Plant, Contra Costa Power Plant, Pittsburg Power Plant, Potrero Power Plant, Moss Landing Power Plant, Morro Bay Power Plant, Diablo Canyon Power Plant, Mandalay Generating Station, Ormond Beach Generating Station, Scattergood Generating Station, El Segundo Generating Station, Redondo Beach Generating Station, Harbor Generating Station, Alamitos Generating Station, Haynes Generating Station, San Onofre Nuclear Generating Station, Encina Power Plant, and South Bay Power Plant.

Implementing the Policy will:

1. Address the adverse impacts associated with uncontrolled OTC facilities by reducing impingement mortality and entrainment;
2. Establish technology-based performance standards that will implement CWA §316(b) and replace the 35 year old interim BPJ-permitting approach.
3. Provide clear standards and guidance to permit writers to ensure consistent implementation across Regional Water Boards.
4. Coordinate implementation at the state level to address cross-jurisdictional concerns such as air emissions impacts and transmission grid stability.
5. Reduce the resource burden on the Regional Water Boards that would continue under the existing BPJ-permitting approach.

1.8 DOCUMENT ORGANIZATION

The remainder of this Supplemental Environmental Document is organized into the following sections:

Section 2—Background
Section 3—Available Technology-based Control Measures
Section 4—Issues and Alternatives
Section 5—Environmental Effects of the Proposed Policy
Section 6—Economic/Benefits
Appendix A—Proposed Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling
Appendix B—Draft Environmental Checklist
Appendix C—Joint Proposal of Energy Agencies (July 2009)
Appendix D—Final Expert Review Panel Responses (July 2008)
Appendix E—Entrainment and Impingement Estimates (Steinbeck, July 2008)
Appendix F—Entrainment and Impingement Estimates Updated for Delta Plants. (Steinbeck, January 2010)
Appendix G—Staff Responses to Public Comments

2.0 BACKGROUND

The State's active OTC power plants are located in coastal or estuarine settings where they have access to large volumes of seawater or estuarine water for cooling purposes. These 19 facilities are permitted to withdraw more than 15 BGD combined, while providing more than 19,000 MW of generation capacity. However, many of these facilities are older and not operated at maximum capacity, and therefore only withdraw ten BGD, on average.[53] OTC power plants are located along the State's entire coastline from Humboldt Bay in the north to San Diego Bay in the south, with most facilities concentrated along the Southern California Bight from Point Conception to the US-Mexico border.

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[53] Steinbeck, 2008. Appendix A.

Facilities subject to the Policy are located in the Regions adjoining the Pacific Ocean (Regions 1, 2, 3, 4, 8, and 9) and the Sacramento-San Joaquin Delta (Region 5S).

2.1 ENVIRONMENTAL SETTING

2.1.1 *North Coast (Region 1)*

The North Coast Region (See Figure 1) comprises all regional basins, including Lower Klamath Lake and Lost River Basins, draining into the Pacific Ocean from the California-Oregon state line southern boundary and includes the watershed of the Estero de San Antonio and Stemple Creek in Marin and Sonoma Counties (Figure 1). Two natural drainage basins, the Klamath River Basin and the North Coastal Basin, divide the Region. The Region covers all of Del Norte, Humboldt, Trinity, and Mendocino Counties, major portions of Siskiyou and Sonoma Counties, and small portions of Glenn, Lake, and Marin Counties. It encompasses a total area of approximately 19,390 square miles, including 340 miles of coastline and remote wilderness areas, as well as urbanized and agricultural areas.

Beginning at the Smith River in northern Del Norte County and heading south to the Estero de San Antonio in northern Marin County, the Region encompasses a large number of major river estuaries, including the Klamath River, Redwood Creek, Little River, Mad River, Eel River, Noyo River, Navarro River, Elk Creek, Gualala River, Russian River, and Salmon Creek. Northern Humboldt County coastal lagoons include Big Lagoon and Stone Lagoon. The two largest enclosed bays in the Region are Humboldt Bay and Arcata Bay in Humboldt County. Another enclosed bay, Bodega Bay, is located in Sonoma County near the southern border of the Region.

Tidelands and marshes are extremely important to many species of waterfowl and shore birds, both for feeding and nesting. Cultivated land and pasturelands also provide supplemental food for many birds, including small pheasant populations. Tideland areas along the north coast provide important habitat for marine invertebrates and nursery areas for forage fish, game fish, and crustaceans. Offshore coastal rocks are used by many species of seabirds as nesting areas. Major components of the economy are tourism and recreation, logging and timber milling, aggregate mining, commercial and sport fisheries, sheep, beef and dairy production, and vineyards and wineries. The largest urban centers are Eureka in Humboldt County and Santa Rosa in Sonoma County.

The Region's only OTC power plant is the Humboldt Bay facility located on the bay's eastern shore a few miles southwest of Eureka, near the entrance from the Pacific Ocean. The facility is less than two miles north of the Humboldt Bay National Wildlife Refuge.

2.1.2 *San Francisco Bay (Region 2)*

The San Francisco Bay Region (See Figure 2) comprises San Francisco Bay, Suisun Bay beginning at the Sacramento River, and San Joaquin River westerly, from a line which passes between Collinsville and Montezuma Island. The Region's boundary follows the borders common to Sacramento and Solano Counties and Sacramento and Contra Costa Counties west of the Markely Canyon watershed in Contra Costa County. All basins west of the boundary, described above, and all basins draining into the Pacific Ocean between the southern boundary of the North Coast Region and the southern boundary of the watershed of Pescadero Creek in San Mateo and Santa Cruz Counties are included in the Region. The Region comprises most of the San Francisco Estuary to the mouth of the Sacramento-San Joaquin Delta. The San Francisco Estuary conveys the waters of the Sacramento and San Joaquin Rivers to the Pacific Ocean. Located on the north central coast of California, the Bay functions as the only drainage

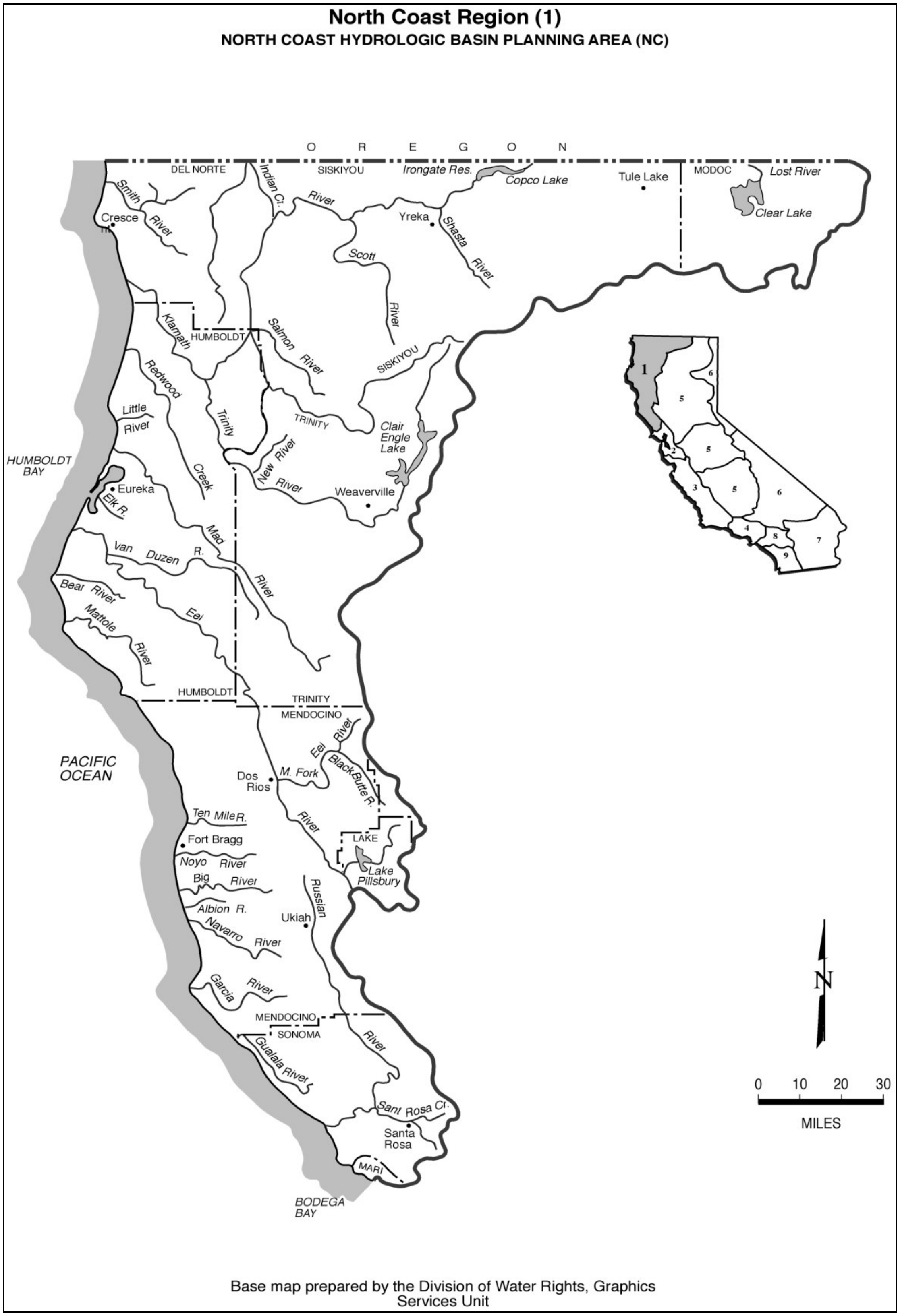

Figure 1. North Coast Region

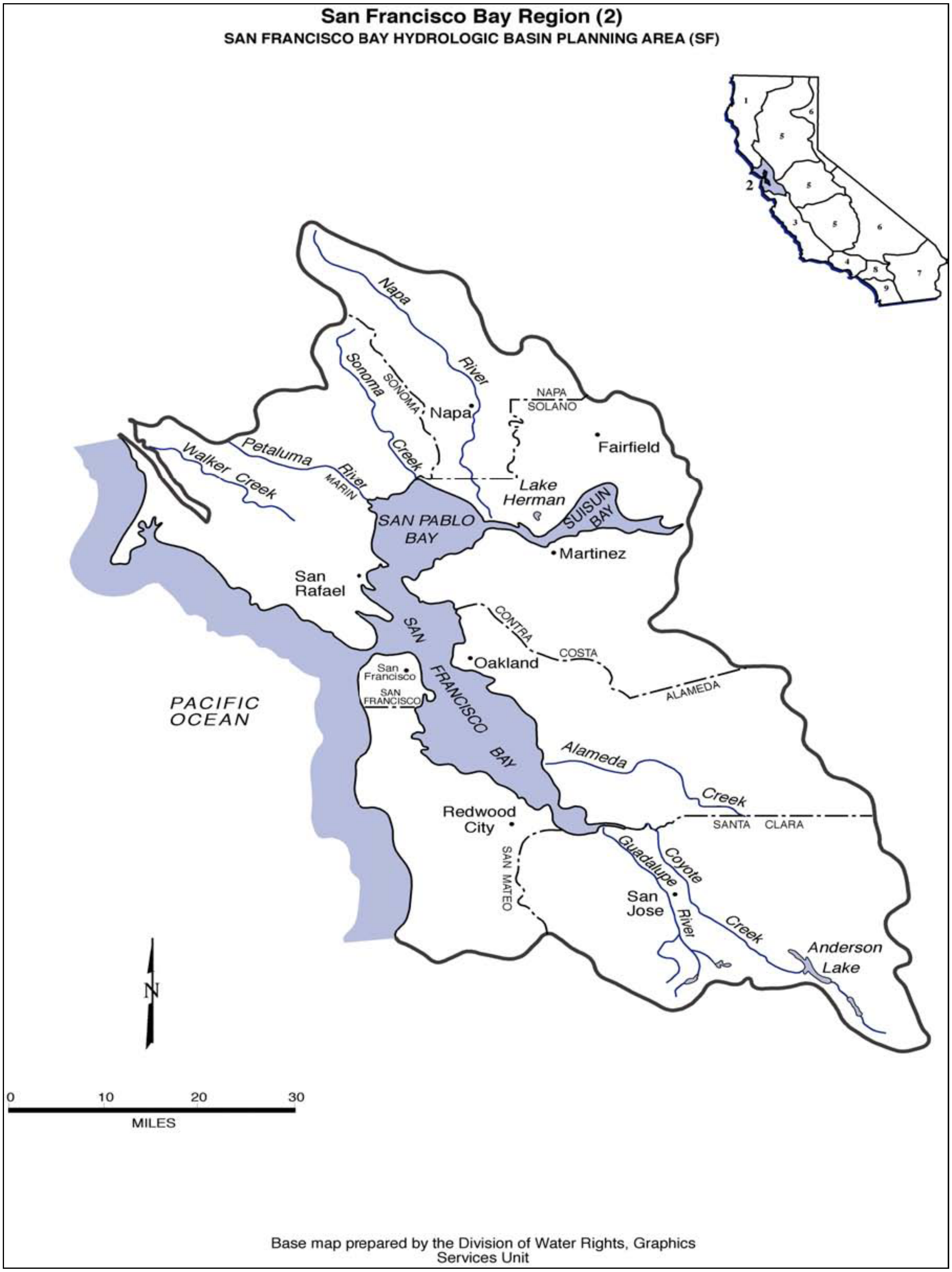

Figure 2. San Francisco Bay Region

outlet for waters of the Central Valley. It also marks a natural topographic separation between the northern and southern coastal mountain ranges.

The Region's waterways, wetlands, and bays form the centerpiece of the fourth largest metropolitan area in the United States, including all or major portions of Alameda, Contra Costa, Marin, Napa, San Francisco, San Mateo, Santa Clara, Solano, and Sonoma Counties. The San Francisco Bay Water Board has jurisdiction over the part of the San Francisco Estuary that includes all of the San Francisco Bay segments extending east to the Delta (Winter Island near Pittsburg). The San Francisco Estuary sustains a highly dynamic and complex environment. Within each section of the Bay system lie deepwater areas that are adjacent to large expanses of very shallow water. Salinity levels range from hypersaline to fresh water, and water temperature varies widely. The Bay system's deepwater channels, tidelands, marshlands, fresh water streams, and rivers provide a wide variety of habitats within the Region. Coastal embayments including Tomales Bay and Bolinas Lagoon are also located in this Region. The Central Valley Water Board has jurisdiction over the Delta and rivers extending further eastward.

The Sacramento and San Joaquin Rivers enter the Bay system through the Delta at the eastern end of Suisun Bay and contribute almost all of the fresh water inflow into the Bay. Many smaller rivers and streams also convey fresh water to the Bay system. The rate and timing of these fresh water flows are among the most important factors influencing physical, chemical, and biological conditions in the Estuary. Flows in the Region are highly seasonal, with more than 90% of the annual runoff occurring during the winter rainy season between November and April.

The San Francisco Estuary is made up of many different types of aquatic habitats that support a great diversity of organisms. Suisun Marsh in Suisun Bay is the largest brackish-water marsh in the United States. San Pablo Bay is a shallow embayment strongly influenced by runoff from the Sacramento and San Joaquin Rivers. The Central Bay is the portion of the Bay most influenced by oceanic conditions. The South Bay, with less freshwater inflow than the other portions of the Bay, acts more like a tidal lagoon. Together these areas sustain rich communities of aquatic life and serve as important wintering sites for migrating waterfowl and spawning areas for anadromous fish.

Two active OTC power plants are located in Region 2. The Potrero Power Plant is located in the San Francisco's Potrero Hill neighborhood, approximately 3.5 miles southwest of Yerba Buena Island in the Central San Francisco Bay. The Pittsburg Power Plant lies on the south bank of Suisun Bay near the confluence of the San Joaquin and Sacramento Rivers.

2.1.3 *Central Coast (Region 3)*

The Central Coast Region (See Figure 3) comprises all basins (including Carrizo Plain in San Luis Obispo and Kern Counties) draining into the Pacific Ocean from the southern boundary of the Pescadero Creek watershed in San Mateo and Santa Cruz Counties; to the southeastern boundary of the Rincon Creek watershed, located in western Ventura County (Figure 3).

The Region extends over a 300-mile long by 40-mile wide section of the state's central coast. Its geographic area encompasses all of Santa Cruz, San Benito, Monterey, San Luis Obispo, and Santa Barbara Counties as well as the southern one-third of Santa Clara County, and small portions of San Mateo, Kern, and Ventura Counties. Included in the Region are urban areas such as the Monterey Peninsula and the Santa Barbara coastal plain; prime agricultural lands such as the Salinas, Santa Maria, and Lompoc Valleys; National Forest lands; extremely wet areas such as the Santa Cruz Mountains; and arid areas such as the Carrizo Plain.

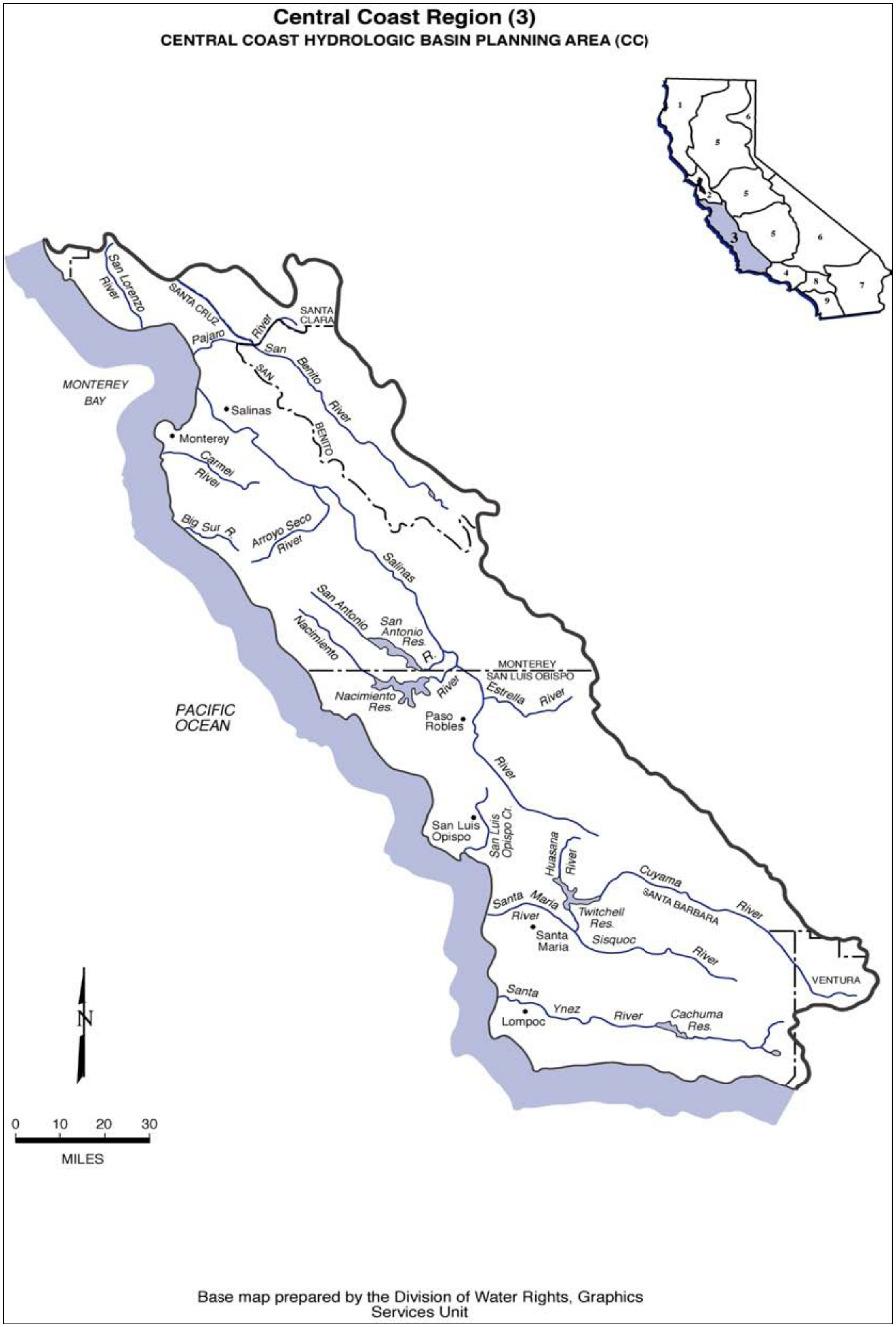

Figure 3. Central Coast Region

Water bodies in the Central Coast Region are varied. Enclosed bays and harbors in the region include Morro Bay, Elkhorn Slough, Tembladero Slough, Santa Cruz Harbor, Moss Landing Harbor, Monterey Harbor, Port San Luis, and Santa Barbara Harbor. Several small estuaries also characterize the region, including the Santa Maria River Estuary, San Lorenzo, River Estuary, Big Sur River Estuary, and many others. Major rivers, streams, and lakes include San Lorenzo River, San Benito River, Pajaro River, Salinas River, Santa Maria River, Cuyama River, Estrella River and Santa Ynez River, San Antonio Reservoir, Nacimiento Reservoir, Twitchel Reservoir, and Cuchuma Reservoir.

Three OTC facilities are located in Region 3. The Moss Landing Power Plant is located approximately 15 miles northeast of Monterey on Moss Landing Harbor near Elkhorn Slough. The Morro Bay Power Plant is located ½-mile due east of Morro Rock and withdraws water at the head of the shallow, enclosed Morro Bay. Diablo Canyon Power Plant, one of the State's two nuclear facilities, is located approximately 7 miles northwest of Avila Beach along an isolated stretch of the Pacific Coastline at the foot of the Irish Hills.

2.1.4 *Los Angeles (Region 4)*

The Los Angeles Region (See Figure 4) comprises all basins draining into the Pacific Ocean between the southeastern boundary of the watershed of Rincon Creek, located in western Ventura County, and a line which coincides with the southeastern boundary of Los Angeles County, from the Pacific Ocean to San Antonio Peak, and follows the divide, between the San Gabriel River and Lytle Creek drainages to the divide between Sheep Creek and San Gabriel River drainages (Figure 4).

The Region encompasses all coastal drainages flowing into the Pacific Ocean between Rincon Point (on the coast of western Ventura County) and the eastern Los Angeles County line, as well as the drainages of five coastal islands (Anacapa, San Nicolas, Santa Barbara, Santa Catalina, and San Clemente). In addition, the Region includes all coastal waters within three miles of the continental and island coastlines. Two large deepwater harbors (Los Angeles and Long Beach Harbors) and one smaller deepwater harbor (Port Hueneme) are contained in the Region. There are small craft marinas within the harbors, as well as tank farms, naval facilities, fish processing plants, boatyards, and container terminals. Several small-craft marinas also exist along the coast (Marina del Ray, King Harbor, Ventura Harbor); these contain boatyards, other small businesses, and dense residential development.

Several large, primarily concrete-lined rivers (Los Angeles River, San Gabriel River) lead to unlined tidal prisms which are influenced by marine waters. Salinity may be greatly reduced following rains since these rivers drain large urban areas composed of mostly impermeable surfaces. Some of these tidal prisms receive a considerable amount of freshwater throughout the year from publicly-owned treatment works that discharge tertiary-treated effluent and industrial effluent.

Santa Monica Bay, which includes the Palos Verdes Shelf, dominates a large portion of the open coastal water bodies in the Region. The Region's coastal water bodies also include the areas along the shoreline of Ventura County and the waters surrounding the five offshore islands in the Region.

Eight of the State's Coastal OTC facilities are located in Region 4. Mandalay and Ormond Beach Generating Stations are located in Ventura County near Oxnard. Ormond Beach withdraws cooling water from a deep offshore location while Mandalay uses water from the Edison Canal and Channel Islands Harbor.

Figure 4. Los Angeles Region

Scattergood, El Segundo, and Redondo Beach Generating Stations are located along the shoreline of Santa Monica Bay. Each withdraws water from deep offshore locations.

Harbor Generating Station is a small combined-cycle unit located in Los Angeles Harbor near Slip 5.

The Alamitos and Haynes Generating Stations are located on opposing banks of the San Gabriel River just north of the Orange County line. Each facility withdraws water from Alamitos Bay through surface, shoreline intakes.

2.1.5 *Central Valley (Region 5S)*

The Central Valley Region includes approximately 40% of the land in California stretching from the Oregon border to the Kern County/ Los Angeles County line. The region is divided into three basins.

The Sacramento River Basin covers 27,210 square miles and includes the entire area drained by the Sacramento River. The principal streams are the Sacramento River and its larger tributaries: the Pitt, Feather, Yuba, Bear, and American Rivers to the East; and Cottonwood, Stony, Cache, and Putah Creek to the west. Major reservoirs and lakes include Shasta, Oroville, Folsom, Clear Lake, and Lake Berryessa (see Figure 5).

The San Joaquin River Basin covers 15,880 square miles and includes the entire area drained by the San Joaquin River. Principal streams in the basin are the San Joaquin River and its larger tributaries: the Consumnes, Mokelumne, Calaveras, Stanislaus, Tuolumne, Merced, Chowchilla, and Fresno Rivers. Major reservoirs and lakes include Pardee, New Hogan, Millerton, McClure, Don Pedro, and New Melones (see Figure 6).

These two river basins cover about one fourth of the total area of the state and over 30% of the state's irrigable land. The Sacramento and San Joaquin Rivers furnish roughly 50% of the state's water supply.

The Sacramento and San Joaquin Rivers meet and form the Delta, which ultimately drains into the San Francisco Bay. The Delta is a maze of river channels and diked islands covering roughly 1,150 square miles, including 78 square miles of water area. Two major water projects located in the South Delta, the Federal Central Valley Project and the State Water Project, deliver water from the Delta to Southern California, the San Joaquin Valley, Tulare Lake Basin, the San Francisco Bay Area, as well as within the Delta boundaries.

Region 5S contains one OTC power plant. The Contra Costa Power Plant is located along the south shore of the San Joaquin River and withdraws water through a shoreline intake structure.

2.1.6 *Santa Ana (Region 8)*

The Santa Ana Region (See Figure 7) comprises all basins draining into the Pacific Ocean between the southern boundary of the Los Angeles Region and the drainage divide between Muddy and Moro Canyons, from the ocean to the summit of San Joaquin Hills; along the divide between lands draining into Newport Bay and Laguna Canyon to Niguel Road; along Niguel Road and Los Aliso Avenue to the divide between Newport Bay and Aliso Creek drainages; and along the divide and the southeastern boundary of the Santa Ana River drainage to the divide between Baldwin Lake and Mojave Desert drainages; to the divide between the Pacific Ocean and Mojave Desert drainages.

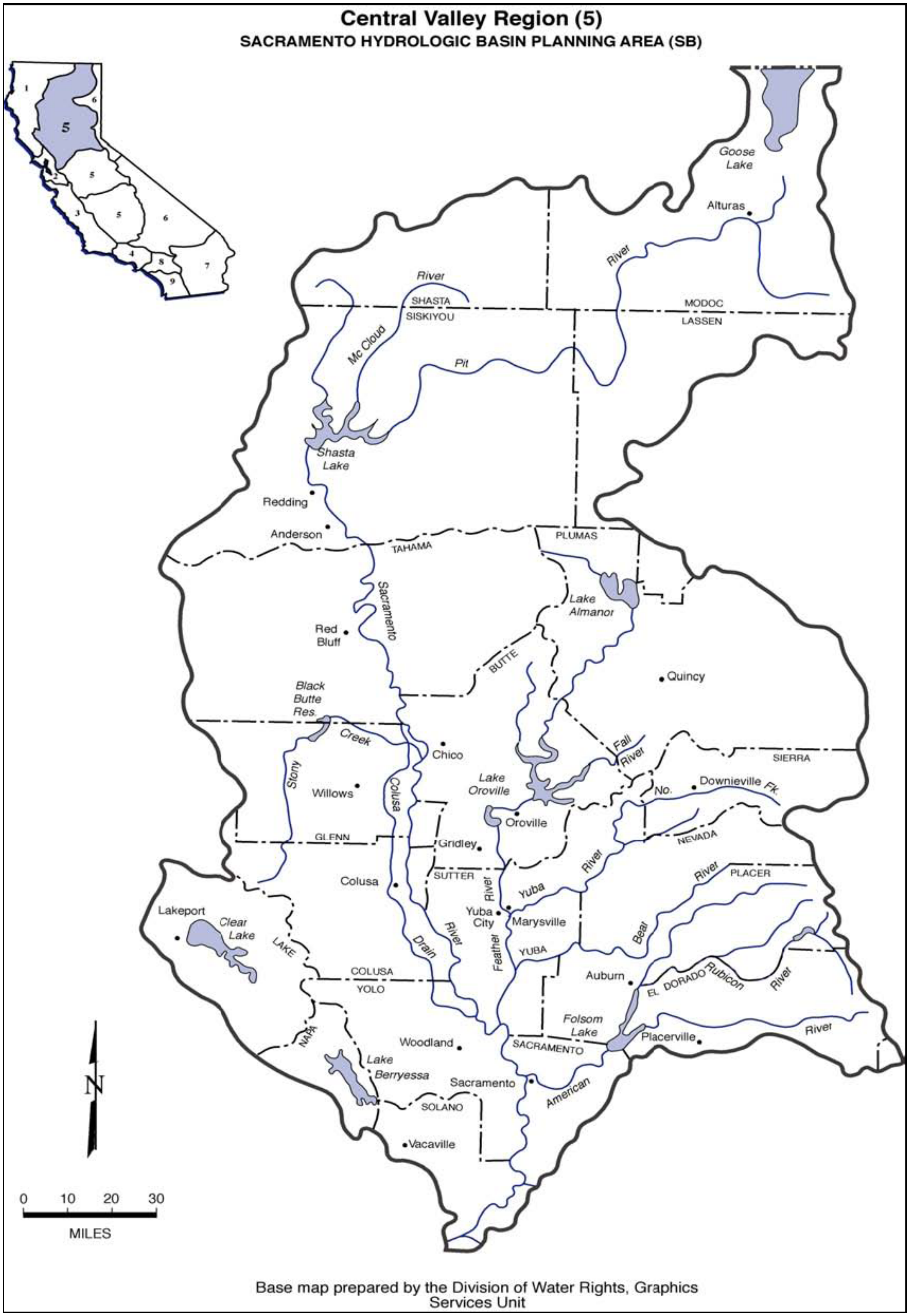

Figure 5. Central Valley Region (Sacramento)

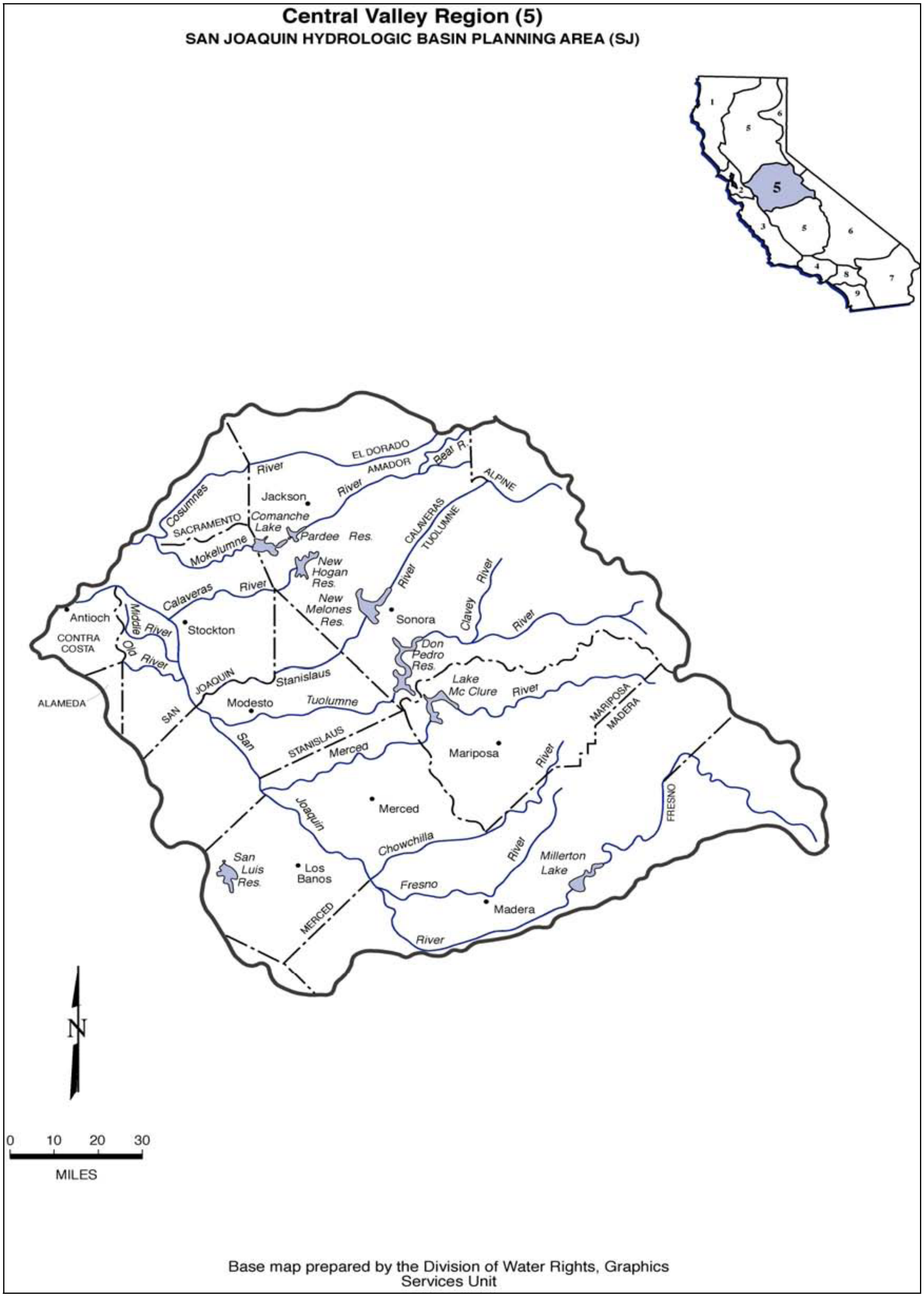

Figure 6. Central Valley Region (San Joaquin)

The Santa Ana Region is the smallest of the nine Regions in the state (2,800 square miles) and is located in southern California, roughly between Los Angeles and San Diego. Although small geographically, the Region's four-plus million residents (1993 estimate) make it one of the most densely populated Regions. The climate of the Santa Ana Region is classified as Mediterranean: generally dry in the summer with mild, wet winters. The average annual rainfall in the Region is about fifteen inches, most of it occurring between November and March. The enclosed bays in the Region include Newport Bay, Bolsa Bay (including Bolsa Chica Marsh), and Anaheim Bay. Principal rivers include Santa Ana, San Jacinto and San Diego. Lakes and reservoirs include Big Bear, Hemet, Mathews, Canyon Lake, Lake Elsinore, Santiago Reservoir, and Perris Reservoir.

Region 8 contains one OTC power plant. The Huntington Beach Generating Station is located in Huntington Beach alongside the Santa Ana River and on the inland side of the Pacific Coast Highway and withdraws water from a deep offshore location.

2.1.7 *San Diego (Region 9)*

The San Diego Region (see Figure 8) comprises all basins draining into the Pacific Ocean between the southern boundary of the Santa Ana Region and the California-Mexico boundary (Figure 12). The San Diego Region is located along the coast of the Pacific Ocean from the Mexican border to north of Laguna Beach. The Region is rectangular in shape and extends approximately 80-miles along the coastline and 40 miles east to the crest of the mountains. The Region includes portions of San Diego, Orange, and Riverside Counties. The population of the Region is heavily concentrated along the coastal strip. Six deepwater sewage outfalls and one across the beach discharge from the new border plant at the Tijuana River empty into the ocean. Two harbors, Mission Bay and San Diego Bay, support major recreational and commercial boat traffic. Coastal lagoons are found along the San Diego County coast at the mouths of creeks and rivers.

San Diego Bay is long and narrow, 15 miles in length and approximately one mile across. A deep-water harbor, San Diego Bay has experienced waste discharge from former sewage outfalls, industries, and urban runoff. Up to 9,000 vessels may be moored there. San Diego Bay also hosts four major U.S. Navy bases with approximately 80 surface ships and submarines. Coastal waters include bays, harbors, estuaries, beaches, and open ocean. Deep draft commercial harbors include San Diego Bay and Oceanside Harbor and shallower harbors include Mission Bay and Dana Point Harbor. Tijuana Estuary, Sweetwater Marsh, San Diego River Flood Control Channel, Kendal-Frost Wildlife Reserve, San Dieguito River Estuary, San Elijo Lagoon, Batiquitos Lagoon, Agua Hedionda Lagoon, Buena Vista Lagoon, San Luis Rey Estuary, and Santa Margarita River Estuary are the important estuaries of the Region.

Region 9 contains 3 OTC power plants. San Onofre Nuclear Generating Station (SONGS), the second of the State's nuclear facilities, is located north of the city of Oceanside on land leased from Camp Pendleton. The Encina Power Plant is located near the city of Carlsbad adjacent to the Aqua Hedionda Lagoon. The South Bay Power Plant is located at the extreme southern end of San Diego Bay in the city of Chula Vista.

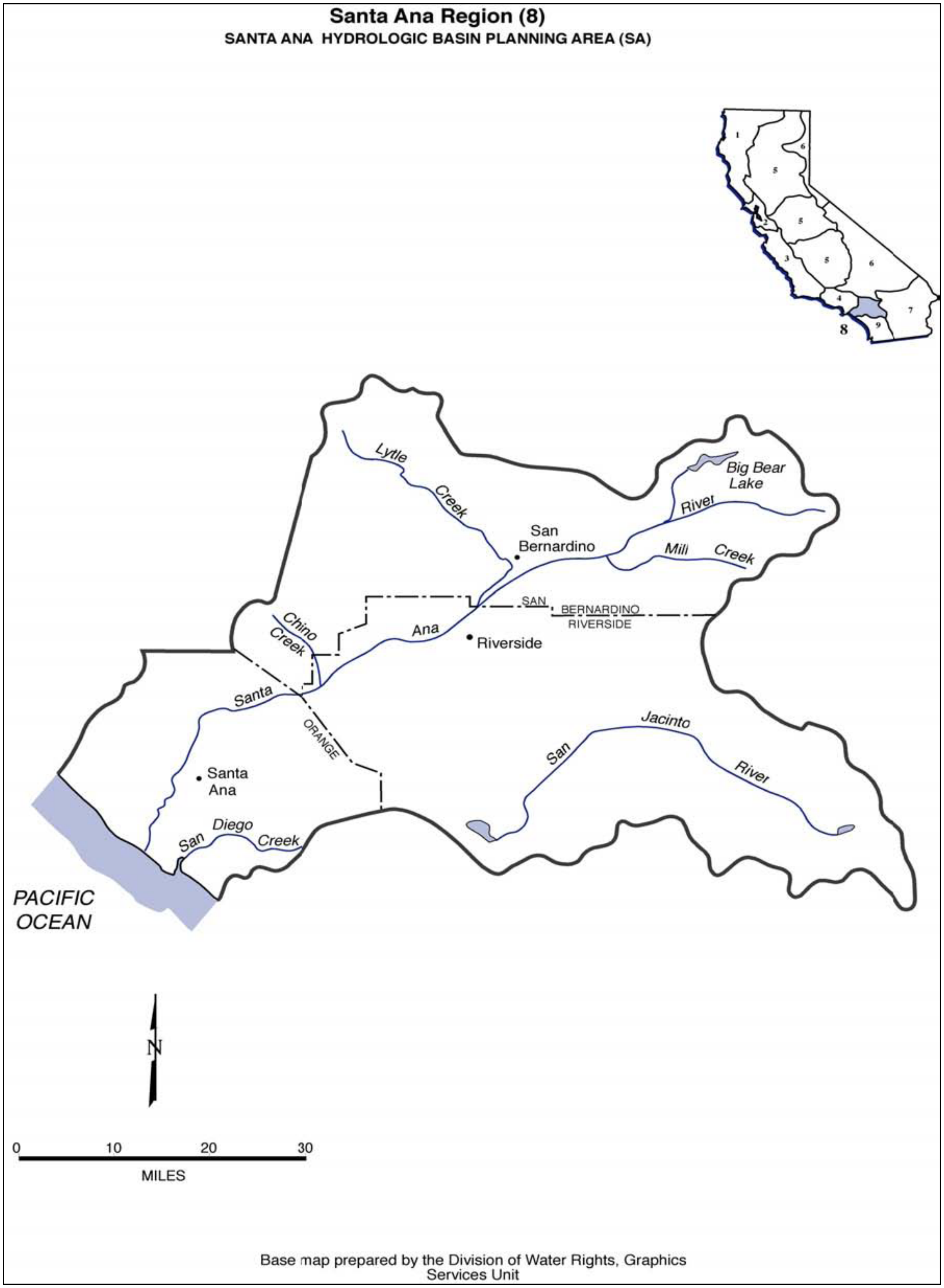

Figure 7. Santa Ana Region

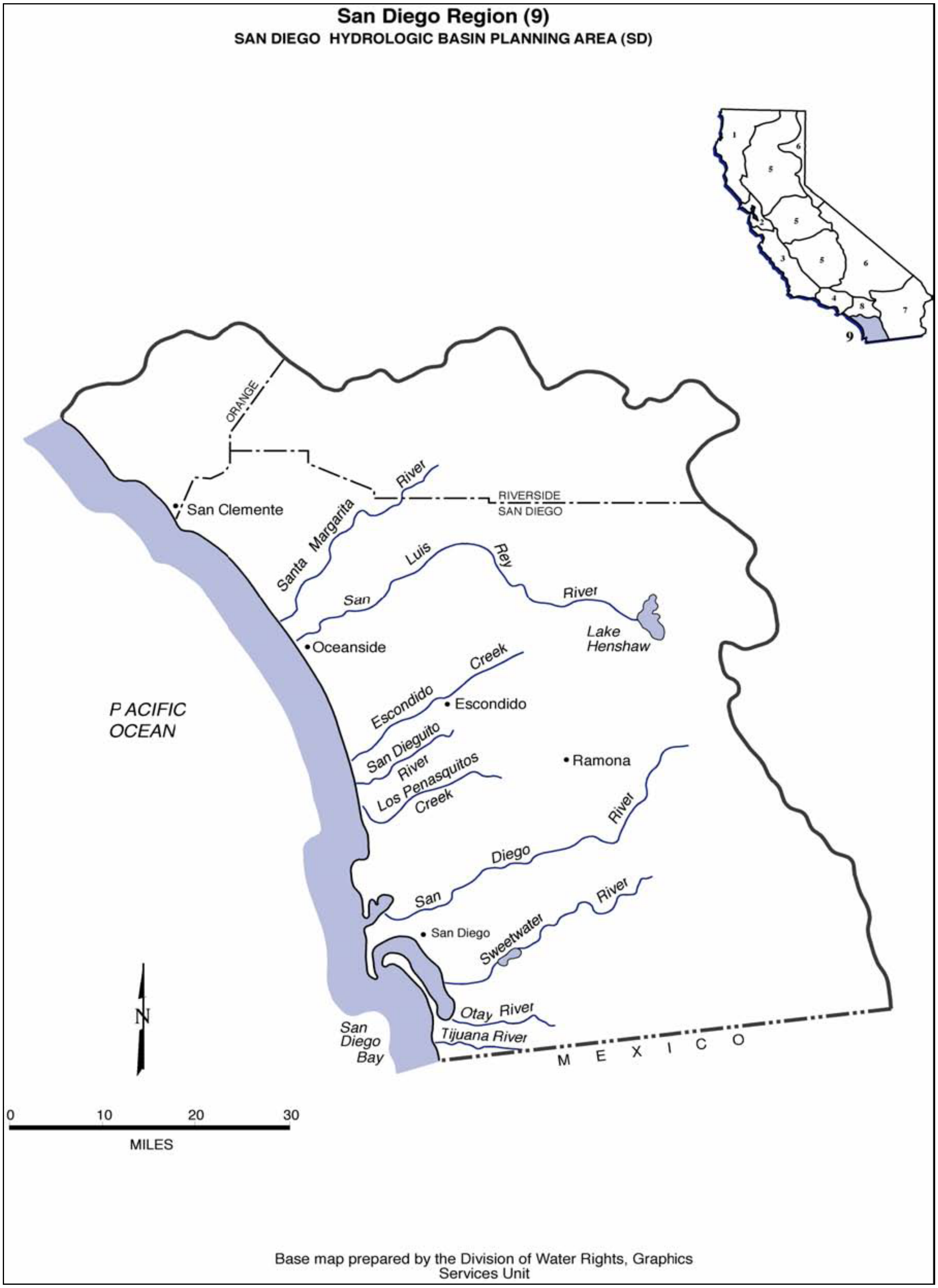

Figure 8. San Diego Region

2.2 BIOLOGICAL AND CUMULATIVE IMPACTS FROM ONCE-THROUGH COOLING

OTC power plants are generally the largest volume dischargers in the State due to their high use of once through cooling water. Discharge volumes range from 78 to 2670 MGD, with the State's nuclear facilities, Diablo Canyon and SONGS, permitted to discharge 2,670 MGD and 2,587 MGD, respectively. The largest discharge volume from a conventional power plant is 1,282 MGD for Alamitos. 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).

Effluent limitations for point source surface water discharges (including power plant discharges) are implemented through NPDES permits and are designed to preserve a receiving water's designated beneficial uses, including aquatic life uses. Significant events that have resulted in fish kills, such as accidental spills or unauthorized discharges, or other violations of the Cal. Wat. Code or Fish and Game Code, are met with enforcement actions. Contrary to all of the limitations and prohibitions placed on discharges, the ongoing fish kills from OTC power plants—through impingement and entrainment—essentially constitute a de facto "take" permit from the State's coastal waters.

The consensus among regulatory agencies at both the state and federal levels is that OTC systems contribute to the degradation of aquatic life in their respective ecosystems. In its 2005 report, the CEC concluded OTC systems were "partly responsible for ocean degradation" and contributed to declining fisheries and impaired coastal habitats through the intake of large volumes of water and the discharge of elevated-temperature wastewater.[54] The development record for both the Phase I and Phase II rules contain numerous documented examples of significant impacts from OTC on aquatic communities, including California.[55]

2.2.1 *Impingement*

Most facilities that obtain cooling water from surface water sources use some method of primary screening to prevent large objects from being drawn through the cooling system, where they may clog or damage sensitive equipment. These screens typically have mesh panels with slot sizes ranging from 3/8 inch to 1 inch and are rotated periodically or removed to clean off any debris, including aquatic organisms.

Impingement occurs when organisms are trapped against the screen as a result of the force of the intake water and are unable to escape. Impinged organisms may asphyxiate if the force of the oncoming water prevents their gills from operating normally. Starvation or mortality from fatigue may result if organisms are held against the screen for prolonged periods. Even those organisms that are able to escape may suffer physical injuries, such as de-scaling, that make them more susceptible to death or predation. Impingement does not, however, always result in the death of the organism. Hardier species, particularly larger ones in their adult phases, are sometimes capable of withstanding the stresses of impingement. Modifications to screening systems may enable the capture and release of organisms before mortality or significant injury can occur.

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[54] *See* CEC. *Issues and Impacts Associated with Once-Through Cooling at California's Coastal Power Plants: Staff Report*. CEC-700-2005-013. 2005.
[55] *See* USEPA, *Regional Analysis Document for the Final Section 316(b) Phase II Existing Facilities Rule*. EPA-821-R-02-003. 2004.

Susceptibility to impingement is dependent on many factors, not the least of which is the target species and its inherent ability to out-swim the current induced by the intake system or its ability to withstand any physical injury that may occur from interaction with the screens. Survival, or avoidance of impingement altogether, is also influenced by the life stage and general health of the target organism. Environmental factors, such as relative areas of light and dark in the vicinity of the intake structure, may also contribute to an increased rate of impingement by triggering behavioral responses. Changes in temperature beyond the optimal range for some species may induce lethargy and impair the organism's ability to avoid or escape from the intake structure. In some cases, these behavioral responses can be exploited to prevent organisms from being impinged, although they are highly species specific and limited in their application.

2.2.2 *Entrainment*

Entrainment is the action of drawing smaller objects through the entire cooling water system, including the pumps and condenser tubes, and discharging them along with the cooling water and other plant wastes. Organisms susceptible to entrainment through cooling water systems are among the most fragile in the aquatic community because of their relatively small size (less than 3/8 inch) and life stage (typically fish eggs and larvae). Planktonic organisms such as these cannot independently escape the influence of an intake system and are instead reliant upon screening mechanisms or other methods to prevent their intake.

Organisms that find themselves entrained through a power plant cooling system will be subjected to dramatic changes in pressures as they pass through the pump and condenser. Water temperatures will rapidly increase by 10 to 25° F, or more, and decrease upon discharge and mixing with the receiving water. Physical injury may occur from the interaction with mechanical equipment and the shearing forces of pumps. Chemicals used to control biofouling in the system, such as chlorine, further complicate the ability of organisms to survive entrainment until they are discharged back to the water body.

Organisms that are entrained are presumed to have been killed, although there is some disagreement whether 100% mortality is a certainty. From a planning perspective, however, whether a very small fraction of entrained organisms survive is immaterial; the impact is substantial enough (i.e., 100% virtual mortality) to warrant action. Accordingly, the preferred method to reduce the adverse effects of entrainment is to prevent the interaction of susceptible organisms and the cooling system altogether. This can be accomplished in one of two ways: the use of a barrier technology with pores small enough to exclude entrainable organisms, or by reducing the facility's intake flow.

2.3 IMPINGEMENT MORTALITY AND ENTRAINMENT DATA

SONGS represents one example of impingement and entrainment impacts. Fish enter the SONGS cooling water system through an offshore cooling water intake, with a velocity cap, and then through a screen well 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.[56] SONGS source water has been assumed by the Marine Review Committee of scientists (established by the California Coastal Commission) to be the entire nearshore of the Southern California Bight. SONGS causes a 13% impact to queenfish standing stock, and also has a substantial effect on white croaker and northern anchovy populations.[57]

The Diablo Canyon facility withdraws seawater directly from an intake cove and through a shoreline intake structure. While impingement mortality is less than at SONGS, likely due to design and habitat differences between the two facilities, entrainment is still significant. Diablo Canyon entrainment 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% 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% over 120 kilometers (75 miles) of coastline during a 1997-98 sampling period.[58]

As an example of a conventional power plant, and based on Duke Energy South Bay LLC's . §316(b) Proposal for Information Collection, the South Bay Power Plant in San Diego Bay, assuming full operation, has an estimated annual impingement of about 386,000 fish, 93% 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.[59] More recent estimates for this plant are provided in Tables 2 and 3 below.

Impingement and entrainment data can be collected and reported using varying methods, making comparisons between facilities difficult. Some data provided in the 2008 Scoping Document were either inaccurate or outdated. The ERP, convened to support the State Water Board's policy development process, tasked one of its members to compile the most recent impingement and entrainment data for the OTC facilities and provide a summary report using standardized methods. The summary report is shown in Appendix E of this document, and that report was updated in January 2010 as shown in Appendix F. Table 2 (Entrainment) and Table 3 (Impingement), are reproduced from these reports prepared by John Steinbeck of Tenera Environmental, a member of the ERP. Entrainment data were mostly compiled from recent studies of cooling water systems at 18 power plants in California. Entrainment estimates are only presented for larval fishes because this is the only taxonomic group and life stage that was sampled consistently across all of the facilities. Table 2 presents two sets of entrainment estimates. The first set (columns titled "Average Concentrations") is calculated using the annual average larval concentrations from the recent studies. The entrainment estimates were calculated by multiplying the larval concentrations by the total annual design and by the average 2000–2005 flows. The other set of entrainment estimates (columns titled "Study Results") is

[56] SCE. *Proposal for Information Collection, San Onofre Nuclear Generating Station.* October 2005.
[57] CEC. An Assessment of the Studies Used to Detect Impacts to Marine Environments by California's Coastal Power Plants Using Once-Through Cooling. 2005.
[58] Diablo Canyon Power Plant Independent Scientist's Recommendations to the Regional Water Quality Control Board, Item no. 15 Attachment 1, Sept. 9, 2005 Meeting.
[59] Duke Energy South Bay LLC. *316(b)Proposal for Information Collection for South Bay (San Diego) Power Plant*. November 8, 2005.

from the published studies, which did not in all cases present estimates for both design and actual flows (shown as ‘nc’). When the draft of this document was prepared and released (July 2009) representative data were not available were the Contra Costa and Pittsburg power plants located in the Sacramento-San Joaquin Delta (Delta) system. However since that time the entrainment study data for Contra Costa and Pittsburg power plants has been made available and included in Table 2. Calculated and reported estimates for Contra Costa and Pittsburg are based on sampling from March 2008 - July 2008 using a 1,600 micron mesh net. Recent data for the Humboldt Bay Power Plant was not available and therefore was not included in Table 2. However it should be noted that the Humboldt Bay Power Plant has nearly completed its re-powering project and will no longer be using OTC in the near future.

Total statewide fish larvae entrainment estimates for these 18 power plants, based on the annual average larval concentrations from the recent studies and for the average 2000-2005 flows, are 19.4 billion annually. If all 18 of the plants (for which there is available data) operated at the design flow capacities (and maximum permitted flows), the total annual statewide fish larvae entrainment estimates would rise to about 29.6 billion. It is important to note that these figures are based on ichthyoplankton, and do not account for invertebrates.

Impingement estimates at 18 power plants are also presented for just fishes because this is the only taxonomic group that was sampled consistently across all of the facilities. Table 3 presents two sets of impingement estimates for both numbers and biomass of fishes. The first set is calculated using the annual average impingement rates during normal operations calculated from the recent studies. The total annual normal operations impingement estimates were calculated by multiplying the impingement rates by the total annual design and average 2000-2005 flows. These impingement estimates for normal operations would be added to the average annual impingement during heat treatments for the plants where heat treatments are used for controlling biofouling inside the cooling system. The other set of impingement estimates is from published studies, which did not in all cases present estimates for both design and actual flows (shown as ‘nc’). These estimates include both normal operations and heat treatment impingement. When the draft of this document was prepared and released (July 2009), recent representative data were not available for the Contra Costa and Pittsburg power plants located in the Delta system. However since that time the impingement study data for Contra Costa and Pittsburg power plants have been made available and included in Table 3. Estimates for Contra Costa and Pittsburg were calculated based on sampling data from November 2007 - October 2008 (no total estimates were provided in the source report). Recent data for the Humboldt Bay Power Plant was not available and therefore was not included in Table 3.

Total statewide fish larvae impingement estimates for these 18 power plants, based on the annual average impingement rates during normal operations plus heat treatments, and for the average 2000–2005 flows, are approximately 2.7 million fish (84,250 pounds) annually. If all 18 of the plants (for which data is available) operated at the design flow capacities (and maximum permitted flows) the total annual statewide fish impingement estimates would rise to about 3.6 million fish (113,883 pounds). It is important to note that these figures are based on fish only, and do not account for invertebrates.

Table 2. Estimated Annual Entrainment

Facility	Design Flow (MGD)	2000-2005 Average Flow (MGD)	Average Larval Fish Concentration (number per cubic meter)	Annual Larval Entrainment Estimated Numbers Based On:			
				Average Concentration and Design Flow	Average Concentration And Average Flow	Study Results and Design Flow	Study Results and Average Flow
Alamitos Units 1 and 2	207	121	2.6096	748,306,544	437,854,835	nc	121,970,937
Alamitos Units 3 and 4	392	281	2.6096	1,414,971,165	1,013,733,478	1,109,972,442	728,944,910
Alamitos Units 5 and 6	674	413	2.6338	2,455,020,121	1,503,394,233	nc	835,841,962
Contra Costa Units 6 & 7 [1]	440	257	0.0610	37,098,716	21,669,023	37,098,716	21,669,023
Diablo Canyon	2,528	2,287	0.5051	1,765,916,778	1,597,319,020	nc	1,481,948,383
El Segundo Units 1 and 2	207	69	0.5160	147,969,610	49,437,254	nc	35,743,328
El Segundo Units 3 and 4	399	265	0.5160	284,430,472	189,290,759	276,934,913	186,532,003
Encina	857	621	3.6844	4,366,667,796	3,162,648,118	4,494,849,115	3,627,641,744
Harbor	108	59	1.0464	156,285,731	85,447,634	153,331,013	65,298,000
Haynes	968	258	3.2500	4,349,235,947	1,159,662,085	4,527,644,084	3,649,208,392
Huntington Beach	514	179	0.4216	299,647,084	104,339,074	344,570,635	nc
Mandalay	253	234	0.4000	140,195,151	129,201,071	141,736,337	33,422,317
Morro Bay	668	257	0.8991	830,540,168	318,942,511	859,337,744	nc
Moss Landing Units 1 and 2	361	193	1.1700	584,101,411	311,537,103	522,319,740	nc
Moss Landing Units 6 and 7	865	387	0.7813	934,658,478	418,350,825	888,204,836	nc
Ormond Beach	685	521	0.0446	42,276,804	32,133,537	40,810,043	6,351,783
Pittsburg Units 5-7 [2]	506	274	0.0996	69,678,481	37,731,035	69,678,481	37,731,035
Potrero	231	193	0.9490	303,519,077	252,843,159	289,731,811	nc
Redondo Units 5 and 6	217	51	1.1847	354,702,404	83,037,227	356,000,276	101,659,379
Redondo Units 7 and 8	675	254	0.8276	772,198,644	290,801,357	744,808,585	189,537,344
SONGS Unit 2	1,219	1,139	1.9649	3,311,307,168	3,095,251,683	nc	3,555,787,272
SONGS Unit 3	1,219	1,154	1.9649	3,311,307,168	3,136,923,690	nc	3,261,783,562
Scattergood	495	309	0.7387	506,083,227	315,634,578	524,202,652	365,258,133
South Bay	601	417	2.8925	2,404,046,574	1,667,406,878	2,420,527,779	nc

Notes: nc = not calculated in report

Table 3. Estimated Annual Impingement

Facility	Design Flow (MGD)	2000-2005 Average Flow (MGD)	Average (number per MGD)	Average Biomass (pounds per MGD)	Annual Normal Operations Impingement Based On:				Heat Treatments (HT)			Total Annual Impingement Estimate Based On:			
					Count and Design Flow (number)	Biomass and Design Flow (pounds)	Count and Average Flow (number)	Biomass and Average Flow (pounds)	Average number per HT	Average Biomass per HT (pounds)	Average Number of HTs per year (2000-2005)	Design Flow (number)	Design Flow (pounds)	Actual Flow (number)	Average Flow (pounds)
Alamitos Units 1 and 2	207	121							n/a	n/a	n/a				
Alamitos Units 3 and 4	392	281	0.175	0.0076	81,419	3,514	52,106	2,249	n/a	n/a	n/a	81,419	3,514	52,106	2,249
Alamitos Units 5 and 6	674	413							n/a	n/a	n/a				
Contra Costa Units 6&7	440	257	0.2782	0.0053	44,702	849	26,110	496	n/a	n/a	n/a	44,702	849	26,110	496
Diablo Canyon	2,528	2,287	0.0058	0.0009	5,330	785	4,821	710	n/a	n/a	n/a	5,330	785	4,821	710
El Segundo Units 1 and 2	207	69	0.0103	0.0035	779	265	260	89	227.25	72.18	1.3	1,074	359	556	182
El Segundo Units 3 and 4	399	265	0.022	0.0068	3,209	995	2,136	662	229	94.6	3.7	4,057	1,345	2,983	1,012
Encina	857	621	0.6128	0.0256	191,824	8,016	138,932	5,806	15,831.83	747.7	6	286,815	12,502	233,923	10,292
Harbor	108	59	0.4945	0.1622	19,508	6,399	10,666	3,498	n/a	n/a	n/a	19,508	6,399	10,666	3,498
Haynes	968	258	0.1893	0.0041	66,901	1,462	17,838	390	n/a	n/a	n/a	66,901	1,462	71,838	390
Huntington Beach	514	179	0.4079	0.0227	76,582	4,270	26,666	1,487	5,887.00	338.7	4.8	104,840	5,895	54,924	3,112
Mandalay	253	234	0.794	0.0299	73,497	2,771	67,733	2,553	101.9	4.2	1.4	73,640	2,776	67,876	2,559
Morro Bay	668	257	0.3497	0.014	85,315	3,419	32,763	1,313	n/a	n/a	n/a	85,315	3,419	32,763	1,313
Moss Landing Units 1 and 2	361	193	0.5804	0.0058	76,526	762	40,816	406	n/a	n/a	n/a	76,526	762	40,816	406
Moss Landing Units 6 and 7	865	387	1.7895	0.0287	565,390	9,071	253,067	4,060	n/a	n/a	n/a	565,390	9,071	253,067	4,060
Ormond Beach	685	521	0.0711	0.0164	17,806	4,094	13,534	3,112	677.8	87.2	4.5	20,856	4,487	16,584	3,504
Pittsburg Units 5, 6, and 7	506	274	0.1426	0.0021	26,360	390	14,274	211	n/a	n/a	n/a	26,360	390	14,274	211
Potrero	231	193	1.509	0.0337	127,464	2,847	106,182	2,371	n/a	n/a	n/a	127,464	2,847	106,182	2,371
Redondo Units 5 and 6	217	51	0.0075	0.0034	593	268	139	63	10.08	7.32	2	613	282	159	77
Redondo Units 7 and 8	675	254	0.024	0.0085	5,913	2,084	2,227	785	157.5	37.9	4.8	6,669	2,266	2,983	967
SONGS Unit 2	1,219	1,139	1.5787	0.0335	1,405,342	29,854	1,322,490	28,094	2,494.00	627.8	7.5	1,424,047	34,563	1,341,195	32,802
SONGS Unit 3	1,219	1,154									7.8				
Scattergood	495	309	0.8226	0.0814	148,840	14,727	92,829	9,185	10,155.00	788.4	5.2	201,646	18,827	145,635	13,285
South Bay	601	417	1.5921	0.0049	349,490	1,082	242,401	751	n/a	n/a	n/a	349,490	1,082	242,401	751

Notes: n/a= not applicable

2.3.1 *Cumulative Impacts*

There are numerous stressors on marine and estuarine life in California waters. Besides impingement and entrainment at power plants, other stressors include fishing, habitat change, pollution, competition with invasive species, and potentially climate change. The Marine Life Protection Act Science Advisory Team (SAT), made up of 20 scientists, in 2009 identified three major water quality threats in the Southern California Bight with regard to placement of Marine Protected Areas (MPAs). In order of priority, these were: (1) intakes/discharges from power generating facilities; (2) storm drain effluents; and (3) wastewater effluents. In their guidance on placement of MPAs, the SAT stated: "Intakes from power generating facilities are the greatest threat because they operate year round or over many months and there is virtually complete mortality for any larvae entrained through the cooling water intake system."[60]

Further research is needed on the cumulative effects of closely situated power plants withdrawing cooling water from the same water body. If OTC continues to be used by plants in close proximity on the same water body, a cumulative ecological study should be considered. A cumulative impact analysis would 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. In addition, plant-specific impacts associated with the use of OTC occur in conjunction with other anthropogenic impacts in a regional area.

Cumulative impacts are especially important in the Southern California Bight where many power plants are situated within several miles from each other. 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 up to 1.4% of the larval fishes in the Bight. In the same study, for eleven coastal power plants in the same area, the estimated cumulative impingement was approximately 3.6 million fish. Considering only recreational fish species, impingement was somewhere between 8-30% of the number of fish caught in the Southern California Bight.[61]

2.3.2 *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, National Marine Fisheries Service, U.S. Fish and Wildlife, 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 (ESA)[62], 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[63], the term "take" means to harass, hunt, capture, or kill, or attempt to harass, hunt, capture, or kill any marine mammal. Incidental taking

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[60] MLPA Master Plan Science Advisory Team, Draft Recommendations for Considering Water Quality and MPAs in the MLPA South Coast Study Region, Draft revised May 12, 2009
[61] CEC. Issues and Environmental Impacts Associated with Once-Through Cooling at California's Coastal Power Plants. 2005.
[62] 16 U.S.C. §§ 1531 - 1544.
[63] 16 U.S.C §§ 1361 - 1407.

is defined as an unintentional, but not unexpected, taking. Harassment under the 1994 Amendments to the Marine Mammal Protection Act is statutorily defined as any act of pursuit, torment, or annoyance which has the potential to injure a marine mammal or marine mammal stock in the wild (Level A Harassment); or, 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 (Level B Harassment).

Some power plants have applied for incidental take permits from the US Fish and Wildlife and National Marine Fisheries Service. 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.

Impingement at power plants has the potential to directly cause mortality or takes of endangered species. For example, tidewater gobies (*Eucyclogobius newberryi*), federally listed as endangered, are native to coastal lagoons, estuaries, and marshes[64]; these gobies have been known historically to inhabit Humboldt Bay, San Francisco Bay and the Sacramento/San Joaquin Delta, Morro Bay, Los Angeles Harbor and Agua Hedionda Lagoon. White Abalone (*Haliotis sorenseni*) and Black abalone (*Haliotis cracherodii*) inhabit California's coastal ocean waters. White abalone[65] and black abalone[66] are listed as endangered under the federal ESA.

The Contra Costa Power Plant has been known to entrain Chinook salmon.[67] The Contra Costa Power Plant has also been shown to entrain and the Delta smelt *Hypomesus transpacificus* and the Longfin smelt *Spirinchus thaleichthys* (about 35862 and 9233 per year, respectively). The Pittsburg Power Plant has been shown to entrain Delta smelt and Longfin smelt (about 13510 and 20148 per year, respectively). The Pittsburg Power Plant also has been shown to impinge Delta smelt and Longfin smelt (about 48 and 12 per year, respectively). Delta smelt are listed as threatened under both federal and California Endangered Species Acts, and the Longfin smelt is listed under the California Endangered Species Act.[68] In these cases and any others where threatened or endangered species are taken, site-specific impacts such as these must be minimized and ultimately mitigated.

2.4 STATUS OF COASTAL POWER PLANTS IN CALIFORNIA

In California, 19 power plants currently are permitted to use OTC for electrical energy production. These coastal plants are situated in ocean, bay, and estuary environments and are permitted to use more than 15 BGD of OTC water. Actual flows for the 18 plants shown in Tables 2 and 3 are about 10.2 MGD, based on averages of data from 2000 to 2005. Table 4, below, provides a summary of California's OTC power plants. Note that Humboldt Bay Power Plant is not included in this table (and many of the other tables in this document) because it has almost completed the process of repowering the facility with dry cooling.

Table 4. California OTC Power Plants

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[64] http://www.fws.gov/arcata/es/fish/Goby/goby.html
[65] http://www.dfg.ca.gov/mlpa/response/abalone.pdf
[66] http://www.biologicaldiversity.org/news/press_releases/2009/black-abalone-01-13-2009.html
[67] Mirant Delta, LLC. *316(b) Proposal for Information Collection for the Contra Costa Power Plant*. April 2006
[68].Mirant Delta, LLC, Entrainment and Impingement Monitoring Plan for IEP, Annual Report Nov. 2007- Oct. 2008 Contra Costa and Pittsburg Power Plants, July 2009

Facility (Location)	Design Flow (MGD)	Water Body Type	Unit	In-service Year	2001–2006 Capacity Utilization (%)	Dependable Capacity (MW)
Alamitos Generating Station (Long Beach)	1,273	Enclosed Bay/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/Delta	6	1964	16.4	340
			7	1964	23.1	340
Diablo Canyon Power Plant (Avila Beach)	2,528	Ocean	1	1985	89.9	1103
			2	1986	89.3	1099
El Segundo Generation Station (El Segundo)	399	Ocean	3	1964	19.4	335
			4	1965	24.8	335
Encina Power Station (Carlsbad)	857	Enclosed Bay/Estuary	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)	968	Enclosed Bay/Estuary	1	1962	20.5	1606
			2	1963		
			5	1966		
			6	1967		
			8	2005		
Huntington Beach Generating Station (Huntington Beach)	514	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)	668	Enclosed Bay/Estuary	3	1962	18.8	300
			4	1963	18.8	300
Moss Landing Power Plant (Moss Landing)	1,226	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)	685	Ocean	1	1971	16.3	806
			2	1973	17.7	806
Pittsburg Power Plant	495	Estuary/Delta	5	1960	23.7	325
			6	1961	21	325
Potrero Power Plant (San Francisco	231	Enclosed Bay/Estuary	3	1956	38.1	207
Redondo Beach Generating Station (Redondo Beach)	892	Ocean	5	1954	4.9	179
			6	1957	5.6	175

Facility (Location)	Design Flow (MGD)	Water Body Type	Unit	In-service Year	2001–2006 Capacity Utilization (%)	Dependable Capacity (MW)
			7	1967	22.2	493
			8	1967	19.6	493
SONGS (San Clemente)	2,438	Ocean	2	1983	86.8	1127
			3	1984	79.4	1127
Scattergood Generating Station (Los Angeles)	495	Ocean	1	1958	22.1	803
			2	1959		
			3	1974		
South Bay Power Plant (Chula Vista)	601	Enclosed Bay/Estuary	1	1960	39.8	136
			2	1962	38.7	136
			3	1964	27.9	210
			4	1971	6.8	214

Table 5, below, summarizes OTC flow in billion gallons per day (BGD) and energy production in megawatt-hours (MWh) for active OTC power plants in California. Collectively, the OTC power plants produce a sizable fraction of California's energy, as large as 35% in 2001. Table 5 also shows that the fraction of State energy generated by OTC power plants seems to be trending downward with time, producing only 20% in 2005; this trend is likely to continue. CAISO has forecasted that 1000 megawatts (MW) of new generation must be added each year just to keep pace with the State's increasing demand for electricity. However the demand forecast adopted by the CEC in the 2009 EPR report is now 750MW per year on average on a statewide basis. That would be expected to be reduced still further if the additional energy efficiency programs, distributed generation and combined heat and power policy initiatives, called for as part of the AB32 Scoping Plan to achieve greenhouse gas emission reductions, were to be implemented and successful.

Table 5. Flow and Energy Production Summary for OTC Power Plants

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

Note :

a. 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-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 2001-2005. Year 2000-2003 flows for SONGS Units 2 and 3 were estimated using the average of 2004 and 2005 flows.

b. Provided by the California Energy Commission (CEC). Downloaded from USEPA's Clean Air Markets website: http://www.epa.gov/airmarkets/emissions/raw/index.html . Energy generation data was based on gross plant output. GWh = gigawatt hours.

c. Total electrical energy use for California from all in-state and out-of-state generation. Source: California Energy Commission website (www.energy.ca.gov)

Figure 9, below, shows the percentage each OTC power plant provided towards the total energy generated for California in 2005. Note that some OTC power plants provide a small contribution to total energy produced when compared with the total energy 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 electricity can be reliably imported from other sources (i.e. hydroelectric, solar, wind, out of state generators, etc.)[69].

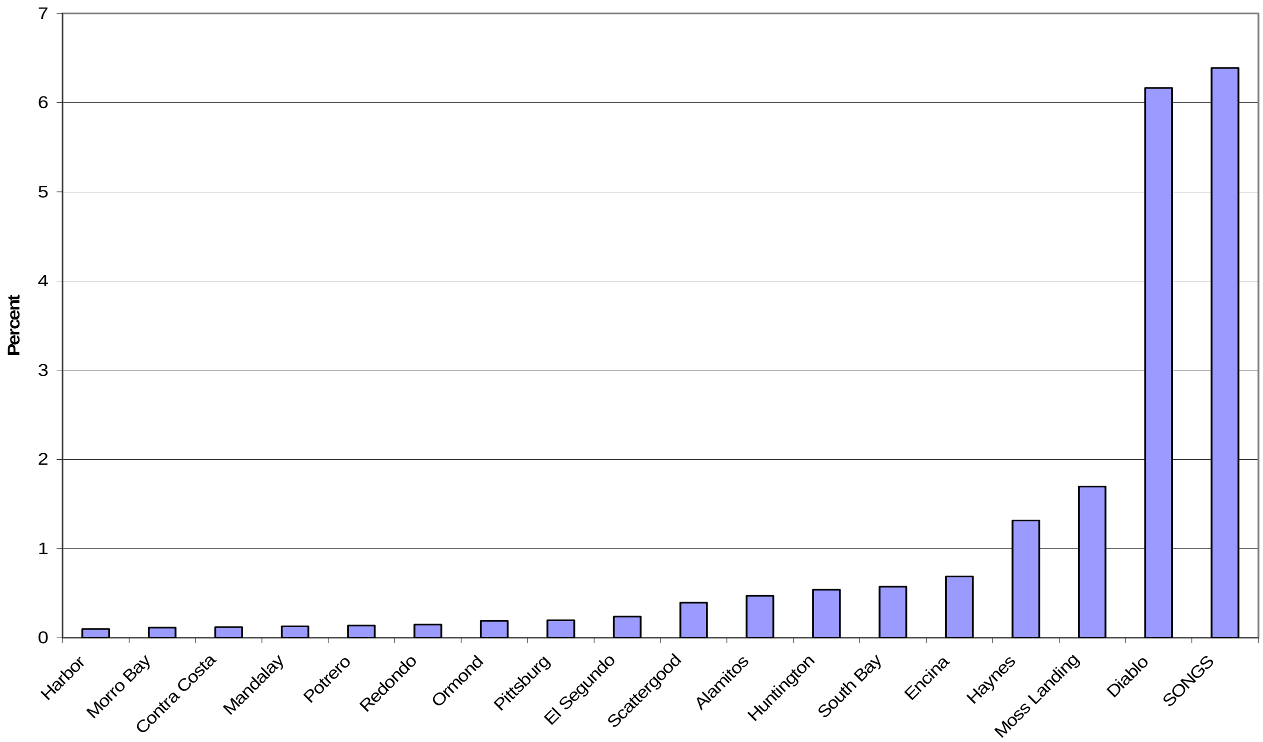

Figure 9. Percentage of Total Energy Production by OTC Power Plants in 2005

Information from CAISO have aided in determining which of the OTC power plants are essential for grid reliability. This information, and further future studies, will help provide a plan for the retirement of the aging/inefficient power plants aligned with the commissioning of new power plants that will facilitate maintaining the reliability of the electrical grid. Even though the OTC power plants did not provide as much energy to the grid in 2005 as they have in the past, it is evident from CAISO comments, and similar comments from the CEC[70], 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.

2.5 COOLING WATER FLOWS

As shown by the flow and energy generation data in Table 5, OTC power plants utilize a significant amount of cooling water. In Figure 10, the 2000–2005 combined annual cooling water flows versus energy generation are plotted. Figure 10 shows that the total energy generated by the OTC power plants (in GWh) and cooling water flow (in billions of gallons (BG)) are linearly correlated.

[69] Jim Detmers. CAISO Comment Letter – Proposed Statewide Policy for Once-Through Cooling. September 15, 2006.
[70] 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.

While Figure 10, below, shows that significant OTC water is used for the generation of energy and that overall cooling water flow and energy 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.

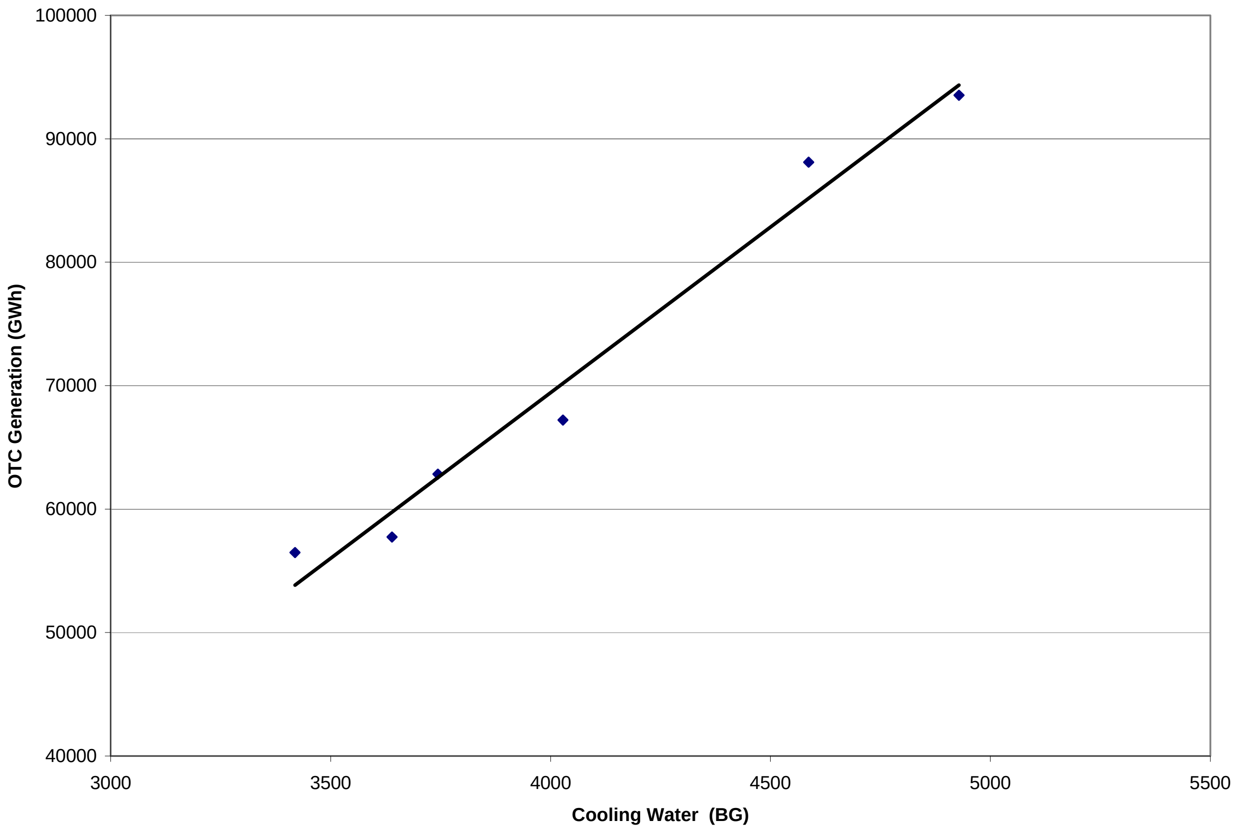

Figure 10. 2000-2005 Combined Annual Cooling Water Flow Versus Total Energy Generated by the OTC Power Plants

Figure 11, below, shows the long-term average ratio of OTC flow to energy generated for the OTC power plants in California. The lower the flow to energy generation ratio, the less cooling water is used per unit energy generated. Figure 11 shows that the volume of cooling water (in millions of gallons) required per MWh generated is highly variable between power plants and that, in general, combined-cycle power plants use less cooling water per MWh than steam boiler systems to produce the same amount of energy. Haynes Units 9&10, Moss Landing Units 1-4, and Harbor Power Plant, which employ combined-cycle technology, have some of the lowest ratios of amount of cooling water flow required to amount of energy generated. In some cases,

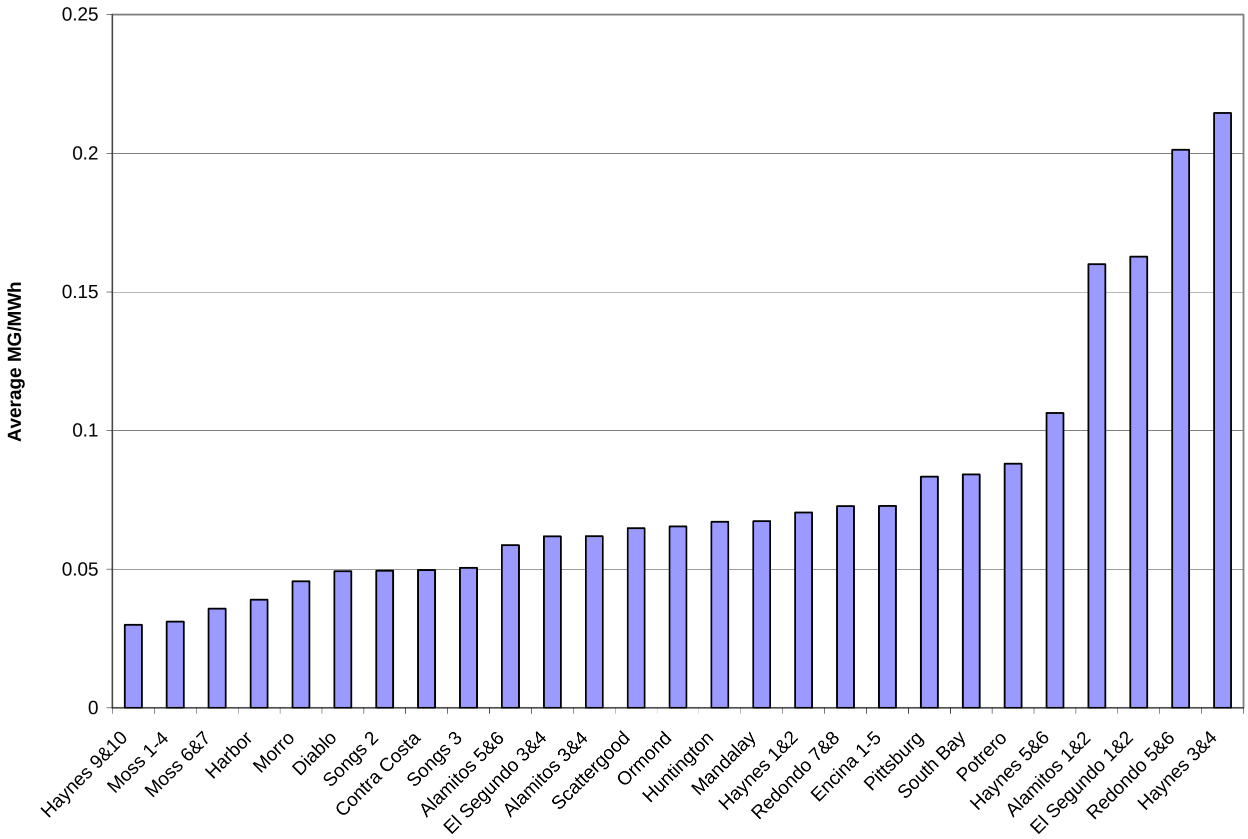

Figure 11. Ratios of Average Cooling Water Flow to Energy Generation

the ratios of cooling water flow to generated electricity are elevated because the power plants operate the cooling water system operation without the production of energy.

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, below, presents monthly median cooling water flows for OTC power plants during summer (June-September) and winter conditions (October-May). Many of the power plants have greater cooling water flows during the months of June-September as compared with October-May flows. Data from years 2001 and 2005 are shown because these years had the highest and lowest OTC energy generation within the available 2000-2005 data set.

State Water Board staff examined graphs of cooling water flow versus energy generation for most of the OTC power plants. For many power plants, cooling water flow increases with energy generation; however, many of the relationships are not correlated very well. This is because reported gross output values do not necessarily reflect cooling water usage during non-generating activities despite the fact that these activities are critical to the unit's operation. Intake flows vary based on many localized factors, including age and efficiency, condenser design and configuration, source water temperatures, and pumping capacity. Depending on the number of pumps dedicated to each intake structure and the generating capacity at a given

Table 6. Monthly Median Cooling Water Flows

Plant/Units	**2001 Median Monthly Flows (MG)**		**2005 Median Monthly Flows (MG)**	
	Oct-May	**Jun-Sep**	**Oct-May**	**Jun-Sep**
Alamitos Units 1&2	3,214	6,324	1,326	1,518
Alamitos Units 3&4	12,059	11,865	6,117	6,418
Alamitos Units 5&6	20,892	20,555	2,696	10,212
Contra Costa	8,877	10,144	1,288	5,468
Diablo Canyon	74,743	75,823	75,823	75,538
El Segundo Units 1&2	3,987	1,234	1,543	1,580
El Segundo Units 3&4	6,287	10,472	5,175	6,279
Encina Units 1-5	17,919	21,462	16,915	15,022
Harbor	2,136	1,936	1,507	1,666
Haynes Units 1&2	5,751	7,619	5,990	8,321
Haynes Units 3&4	7,392	8,280	--	--
Haynes Units 5&6	9,254	12,682	10,865	11,372
Haynes Units 9&10	--	--	6,422	6,891
Huntington	a	a	7,487	13,643
Mandalay	7,729	7,729	7,145	6,985
Morro	15,160	18,004	453	5,004
Moss Landing Units 1-4	--	--	9,958	10,151
Moss Landing Units 6&7	18,902	22,697	103	5,212
Ormond	20,591	20,937	4,772	13,100
Pittsburg	21,884	29,786	914	6,452
Potrero	6,348	6,838	2,344	6,447
Redondo Units 5&6	a	a	605	1,335
Redondo Units 7&8	a	a	128	6,612
Scattergood	8,177	11,389	7,609	10,818
SONGS Unit 2	a	a	37,269	37,167
SONGS Unit 3	a	a	37,776	37,167
South Bay	12,468	13,491	11,927	11,585

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

time, a facility may be able to shut off one or more pumps and maintain sufficient cooling water flow.

As an example, many of the older fossil-fueled units operate in a peaking or load-following capacity that requires their availability during certain periods of the year as directed by procurement contracts or CAISO policy. Because they are not quick-start generators like simple combustion turbines, these units may be required to maintain a near-ready state so the unit may be brought online in short order, also known as a "hot standby" status.

Nuclear facilities may also be required to operate in a similar mode, sometimes referred to as "hot bypass", in which reactor fuels are consumed but generating activities are bypassed, with all waste heat routed to the condenser. This may be required to maintain the reactor core or perform similar maintenance procedures necessary to comply with NRC standards.

2.6 BASELINE AIR EMISSIONS—CRITERIA POLLUTANTS

Air pollutants are produced as by-products when burning fossil fuels. Fossil-fueled facilities therefore all emit air pollutants when operating. Staff compiled air emission data for the active fossil-fueled OTC facilities using reported values obtained from USEPA's Clean Air Markets database for 2006 (see Table 7, below).[71]

Table 7. 2006 Criteria Pollutant Emissions

Facility	Gross Output (MWh)	SO2 (tons/yr)	NOx (tons/yr)	CO (tons/yr)	TOG (tons/yr)	ROG (tons/yr)	PM10 (tons/yr)
Alamitos	1,747,348	4.1	38.4	520.9	36.4	15.4	11.2
Contra Costa	150,392	0.5	9.9	31.7	2.1	1.3	2.4
El Segundo	644,681	1.2	15.2	162.1	25.2	10.7	14.7
Encina	1,349,960	10.8	92.6	286.2	83.8	41.9	76.9
Harbor	240,581	0.6	27.8	72.9	29.5	2.7	1.7
Haynes	3,614,471	6.3	82.1	55.5	155.2	41.7	49.2
Huntington Beach	1,112,942	4.6	30.8	289.9	22	9.3	10.8
Mandalay	369,373	1.1	8.8	72.3	8.1	2.8	4.8
Morro Bay	338,408	1	54.9	117.9	17.7	7.6	12.1
Moss Landing	6,615,799	11.3	152.5	249	313.5	72.8	111.9
Ormond Beach	489,545	1.4	19.3	106.7	7.9	3.3	5.9
Pittsburg	479,171	1.5	28.6	102	6.1	3.6	8
Potrero	539,055	17	125.2	100.5	6.4	4.3	9.5
Redondo Beach	585,240	1	39.8	553.5	24.2	10.4	12.3
Scattergood	1,595,377	46.3	38.2	589.9	81.9	37.8	44.7
South Bay	1,043,217	4.6	58	451	59.1	29.5	54.3
All Fossil	**20,915,560**	**113.3**	**822.1**	**3762**	**879.1**	**295.1**	**430.4**

Notes:
SO2 = sulfur dioxide
NOx = nitrogen oxides
CO = carbon monoxide
TOG = total organic gases
ROG = reactive organic gases
PM10 = fine particulate matter of 10 microns or less in diameter
tons/yr = tons per year

2.7 BASELINE AIR EMISSIONS—GREENHOUSE GASES

Fossil-fueled facilities all emit the greenhouse gases, methane and carbon dioxide (CO_2). Methane is an organic gas and is included along with other organic gasses in the total organic gas (TOG) category in Table 7; however separate estimates specific to methane are not available. Power plants fueled by natural gas produce carbon dioxide at a rate of approximately 117 pounds per million BTU.[72] Efficiencies of plants, however, determine how much carbon dioxide is produced per MWh. Carbon dioxide emissions for the fossil-fueled OTC power plants are shown in Table 8, below.

[71] http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard
[72] http://www.eia.doe.gov/oiaf/1605/coefficients.html

Table 8. 2006 Carbon Dioxide Emissions

Facility	CO_2 (tons/yr)	CO_2 (lbs/MWh)
Alamitos	1,179,464	1,350
Contra Costa	96,605	1,285
El Segundo	423,262	1,313
Encina	950,340	1,408
Harbor	109,332	1,077
Haynes	1,746,143	966
Huntington Beach	777,045	1,396
Mandalay	217,147	1,176
Morro Bay	195,511	1,155
Moss Landing	2,924,527	884
Ormond Beach	293,630	1,200
Pittsburg	241,705	1,296
Potrero	480,477	1,783
Redondo Beach	422,884	1,445
Scattergood	1,061,683	1,331
South Bay	648,471	1,243
All	**11,857,220**	**1,133**

2.7.1 *Combined-Cycle Generation*

Combined-cycle facilities are more efficient because they generate electricity from a two-stage process—combustion and steam. Waste heat is recovered from the combustion turbine's exhaust to produce and fire a steam turbine. Table 9, below, shows an example of how the difference in efficiency affects carbon dioxide emissions between traditional steam boiler units and combined-cycle units (Moss Landing Units 1 and 2 and Haynes Unit 8) based on 2006 emission data.

Table 9. Comparison of Steam Boiler and Combined-Cycle Efficiencies

	Efficiency (%)	CO_2 (tons/yr)	CO_2 (lbs/MWh)
Non Combined-Cycle Units	35	8,327,338	1,323
Moss Landing unit 1 (1A/2A)	50	1,152,071	837
Moss Landing unit 2 (3A/4A)	50	1,153,289	832
Haynes Unit unit 8 (9/10)	50	1,026,193	834

3.0 ISSUES AND ALTERNATIVES

This section describes the major policy-related issues identified during the scoping and development process and provides a discussion of the State Water Board staff's rationale for the final policy, including the different alternatives considered by staff. Each issue discussion is organized as follows:

Issue: The subject matter or brief question framing the issue followed by an explanation or description of the issue and concerns.

Baseline: A description of how the State and Regional Water Boards currently act on the issue, where applicable.

Alternatives: For each issue or topic, at least two alternatives are provided for consideration. Each alternative is evaluated with respect to the program needs and the appropriate sections within Division 7 of the Cal. Wat. Code .

Discussion: A discussion of each alternative's advantages and limitations as well as any relevant background data, descriptions of related programs or other information.

Staff Recommendation: In this section, a recommended alternative (or combination of alternatives) is identified and proposed for adoption by the State Water Board.

Policy Section: Following each recommendation the reader is directed to proposed language in the proposed Policy presented in Appendix A, where applicable.

3.1 SHOULD THE STATE WATER BOARD ADOPT A STATEWIDE POLICY?

As discussed in Section 1 of this document, the §316(b) regulatory framework for existing facilities has remained unchanged since the CWA's adoption, despite more than 30 years invested by USEPA to develop regulation that set technology-based standards and provide guidance. There are no clear indications from USEPA as to its intent to revise or reissue the suspended Phase II rule, nor is there any certainty of what a revised existing facilities rule would require. Federal regulations at 40 CFR 125.90 (b), however, which requires case-by-case implementation using BPJ, was not suspended and remains the governing §316(b) regulation for all existing facilities. Furthermore, the State Water Board has not adopted any policy or plan that implements §316(b) for existing facilities in lieu of federal regulation.

Baseline:
CWA §316(b) statutory requirements for California's coastal power plants are currently implemented through individual NPDES permits issued by the respective Regional Water Board using a case-by-case, BPJ-based approach. The State Water Board and USEPA (Region IX) provide some oversight and approval of each reissued NPDES permit for the coastal power plants. To date, however, no policy or regulation exist that incorporate technology-based standards and guidance for existing facilities in California.

Alternatives:

1. Delay or defer NPDES permit renewals for OTC facilities pending a revised Phase II rule or other federal action.
2. Continue implementation using BPJ on a case-by-case basis (baseline).
3. Adopt a statewide policy with uniform performance standards and guidance, developed using BPJ on a statewide basis.

Discussion:
Alternative 1 would unnecessarily delay attempts to address the continuing impacts to California's coastal ecosystems caused by uncontrolled OTC (see Section 2 of this document).

As shown in Table 1, above, nearly all of California's coastal OTC facilities either currently operate with administratively extended NPDES permits, or will shortly. For most facilities already operating under an extension, the renewal has been delayed pending the adoption of a state or federal regulation implementing §316(b) for existing facilities. While §316(b) requirements are among the most critical aspects that are addressed by an OTC facility's NPDES permit, the permit covers other important issues related to the facility's discharge (e.g., thermal wastewater, in-plant wastewater) that should be reviewed every five years during the permit renewal process.

USEPA has not publicly declared its intent to reissue or substantially revise the Phase II rule following the *Riverkeeper II* and *Entergy* decisions (see Section 1 of this document). Although it is likely that USEPA will move forward and address the necessary changes required by the Second Circuit's remand in *Riverkeeper II*, it is altogether unclear when such changes will be issued or what form they will take. Given then length of time required to develop and promulgate the initial Phase II rule (Phase II was first proposed in 2002), it may take several more years before a draft rule is proposed for public comment and ultimately finalized. Any litigation would only extend that time frame even further, followed by an implementation process of several more years. In contrast, the State Water Board is much further along in developing a statewide policy for California's OTC facilities, having initiated the process in 2005.

Delaying or deferring any state action maintains the §316(b) status quo for OTC facilities by preserving the NPDES permit conditions currently in effect, which, in some cases, have not been renewed since the 1990s.

Alternative 2 would maintain the current baseline—BPJ permitting on a case-by-case basis implemented by the respective Regional Water Boards. This approach has led to an inconsistent implementation of §316(b)'s technology-based requirements from region to region and has failed to meet Porter-Cologne's directive to attain the "highest water quality which is reasonable[.]"[73] As discussed in Section 2 of this document, impacts from OTC operation have continued, largely unabated, over the 35 years since §316(b) was adopted.

In lieu of national performance standards, the case-by-case, BPJ approach is intended to allow for more consideration of site-specific issues, which then form the basis for a more accurately tailored §316(b) permit requirement. Using this method, each Regional Water Board maintains the discretion to determine for itself whether a facility's cooling system meets the technology-based requirement. Likewise, each Board is able to define "adverse environmental impact" independently and decide whether the appropriate technical and biological studies have been conducted that support its BTA determination.

As might be expected, this has led to inconsistencies in permit requirements between Regional Water Boards. In the Sacramento/San Joaquin Delta, for example, the sensitivity of the local aquatic environment and the presence of several threatened or endangered species have caused the San Francisco and Central Valley Regional Water Boards to place added scrutiny on the Pittsburg and Contra Costa facilities. In response, these facilities have adopted flow reduction measures (e.g., variable speed pumps) and/or operational restrictions that limit intake flow during critical spawning and migrating periods. Both facilities have been required to implement management plans and coordinate their activities with other state and federal agencies.[74] On the other hand, facilities in the Los Angeles Region have operated under BTA

[73] CWC §13000 et seq.
[74] See San Francisco Regional Water Board Order R2-2002-0072 (Pittsburg) and Central Valley Regional Water Board Order 5-01-0107 (Contra Costa).

determinations first made in the 1980s that have not been substantially changed or revisited since.[75] The significant advances made over the last three decades, in both technology and biological assessment methods, would seem to indicate that any BTA determination made more than 20 years ago should be revisited in some fashion to ensure it truly reflects the “best” technology available.

Case-by-case BTA evaluations are cost and labor-intensive efforts that require significant investment by each Regional Water Board so that it can properly consider the different biological, engineering, logistical, and economic issues that comprise a robust analysis. The expertise required in these areas is highly specialized and not always immediately available to a Regional Water Board with limited resources devoted to power plant issues, especially those with only one or two facilities within its jurisdiction. In these cases, the Regional Water Board may not be able to adequately evaluate all of the biological and technical data submitted by the facility and thus would find itself at a disadvantage when determining BTA.

Continuing the BPJ approach also limits the Regional Water Boards’ ability to address secondary concerns that extend beyond its jurisdiction or affect non-water-related issues, such as increased air emissions and electrical reliability.

Alternative 3 addresses the limitations of Alternatives 1 and 2 by instituting in a timely manner a statewide policy, developed using BPJ on a statewide basis that is applicable to all of California’s existing coastal OTC facilities. In doing so, the State Water Board takes action to address, in part, the critical state of California’s coastal ecosystems without waiting for USEPA to act on an unknown future rule that may, or may not, sufficiently protect these important resources. The limited universe and the relative similarity between most facilities subject to the proposed Policy (19 estuarine/marine facilities, most powered by natural gas) versus the broader universe that USEPA must consider (more than 540 coal/natural/gas/oil/nuclear) facilities on five different water body types) allows the State Water Board to ignore considerations that are not applicable to California’s coastal environment and thus adopt a policy that is more closely tailored to the State’s needs.

A statewide policy implements §316(b) with uniform, technology-based performance standards rather than the more variable approach that can occur with the case-by-case BPJ method, which can sometimes blur the distinction between water quality-based and technology-based performance standards as they apply to BTA. By establishing a clear standard and implementation strategy, the proposed Policy reduces the burden that each Regional Water Board must face each time it evaluates and defends a case-by-case BTA determination. Furthermore, and most critically, a statewide policy acknowledges the complexity and interconnectedness of the state’s energy generating systems and transmission grid, considerations that will likely involve other policy areas and require some degree of coordination among different regions and agencies to prevent transmission disruptions and ensure compliance with all state and federal regulations.

Staff Recommendation:
Staff recommends Alternative 3: Adopt a statewide policy to provide statewide consistency in implementing §316(b). The most expedient way to provide guidance to permit writers for renewal of power plant NPDES permits and simultaneously address ongoing OTC impacts is through a statewide policy.

[75] See Los Angeles Regional Water Board Orders 00-082 (Alamitos), 00-081 (Haynes), and 01-057 (Mandalay).

Policy Section(s):
Appendix A, Section 1 (*Introduction*)

3.2 HOW SHOULD NEW AND EXISTING POWER PLANTS BE DEFINED?

CWA §316(b) requires that the location, design, construction, and capacity of cooling water intake structures reflect BTA for minimizing adverse environmental impacts, but does not distinguish between a new or existing facility. USEPA, however, has often made such a distinction when developing regulatory programs (e.g., new source performance standards [NSPS]), recognizing that new facilities are typically better able to comply with more stringent standards by incorporating a new technology into their initial design. Existing facilities, however, might have greater difficulty integrating the same technology into its existing system since the new technology must be able to function without substantially impacting performance. In these cases, regulations often provide for less stringent standards or additional time to achieve an equivalent performance for existing facilities versus new ones. The State Water Board has similarly distinguished new from existing power plants in other policies, such as the *Water Quality Control Plan for Control of Temperature in the Coastal and Interstate Waters and Enclosed Bays and Estuaries of California* (Thermal Plan).

As part of its consent decree (see Section 1 of this document), USEPA developed separate rules for new power plants (Phase I), existing power plants (Phase II), and offshore oil and gas extraction facilities and manufacturers (Phase III).

Baseline:
Apart from one mention at §13142.5(b), the Cal. Wat. Code does not distinguish between new and existing facilities. Likewise, the State Water Board has not adopted any §316(b)-related policy making a similar distinction. USEPA, however, defined both new and existing facilities in the Phase I rule at 40 C.F.R. §125.83. As the only active governing regulation for large power plants at either the state or federal level, Phase I definitions are the baseline for determining a new versus an existing OTC power plant.

Alternatives:
1. Create new definitions for new and existing power plants.
2. Use the existing definitions as defined by USEPA in the Phase I federal regulations (baseline).

Discussion:
The Phase I rule 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)."

The suspended Phase II rule adopted the same general definition framework, but provided several examples meant to clarify when a seemingly "new" facility would be considered existing, and vice versa.[76] In the *Riverkeeper II* decision, however, the Second Circuit found that the Phase II rule inappropriately expanded the scope of what may be considered "new" under Phase I and directed USEPA to adhere to the Phase I definitions or reopen the Phase I definition for notice and comment.[77] The *Entergy* decision did not address this issue, nor has USEPA filed notice to revise the definition. The Phase I definition, therefore, remains the governing regulation.

Cal. Wat. Code §13142.5(b) contains specific requirements for "new or expanded coastal power plants" that mandate the "best available site, design, technology, and mitigation measures feasible shall be used to minimize the intake and mortality of all forms of marine life," but does not define the characteristics of an "expanded" facility. The Cal. Wat. Code s explicit requirement to minimize intake and mortality can be read as more restrictive than §316(b)'s requirement to minimize adverse environmental impact, but it remains unclear whether this requirement would be applicable to a facility meeting the Phase I definition of "existing" or if the term can be considered substantially similar to "expanded."

Alternative 1 would potentially redefine both "new" and "existing" facility more broadly or more narrowly than Phase I. The proposed Policy, for example, could clarify that any fully repowered unit should be considered "new" regardless of whether it increased the intake structure's capacity, or it could expand the criteria used that define an existing facility. Such changes, however, would likely create unnecessary confusion between the proposed Policy and federal regulations. A facility could simultaneously be considered "new" under the state regulation and "existing" under Phase I.

Alternative 2 maintains the existing framework by which new and existing power plants are classified with respect to §316(b) and does not create any state-specific classifications that might differ from the Phase I rule.

By limiting the proposed Policy's scope to existing facilities, this alternative effectively incorporates the Phase I rule into its overall approach to OTC power plants and the impacts they create. Because the IM/E reduction requirements for new facilities under Phase I are comparable to the performance standards established for the proposed Policy, there is no need to reclassify facilities from one category to another. Although no new OTC facilities have been proposed in California in recent years, any new facility would be subject to Phase I requirements, rather than the standards of the proposed Policy, which is reserved for existing facilities.

Staff Recommendation:
Staff recommends Alternative 2: Use the existing definitions for new and existing power plants as defined by USEPA in the Phase I federal regulations. Under this approach, potential conflicts with federal regulations are avoided. A new power plant is any facility subject to 40 CFR Part 125, Subpart I and the definition at 40 CFR. §125.83. In like manner, an existing power plant is defined as any power plant that is not a new power plant.

Policy Section(s):
Appendix A, Section 1.F (*Introduction)*

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[76] 69 FR 41579 (No. 131)
[77] See Riverkeeper, Inc. et al. v. U.S. Environmental Protection Agency, (2nd Cir, January 25, 2007) 475 F.3d 83.

Appendix A, Section 5 (*Definition of Terms*)

3.3 SHOULD THE PROPOSED POLICY DISTINGUISH BETWEEN NUCLEAR AND FOSSIL-FUELED 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."[78]

In *Riverkeeper II,* industry petitioners challenged the Phase II rule on the grounds that USEPA failed to consider the unique safety concerns relating to nuclear-fueled facilities, such as ensuring the stable flow of cooling water necessary for safe reactor operation and shutdown. They contended that any change in the water intake system that would result from certain intake technologies could alter water flows and could affect system stability or safety requirements, all of which are specifically designed to operate with once-through cooling. The Second Circuit concluded, however, that the site-specific compliance alternative deferring to the NRC in the event of a conflict provided sufficient protection for nuclear-fueled facilities and rejected the challenge.[79]

Baseline:
BTA determinations for existing facilities are made on a case-by-case basis by the respective Regional Water Boards. There are no programmatic distinctions between nuclear and fossil-fueled facilities with respect to cooling water regulations.

Alternatives:

1. Grant nuclear-fueled facilities an exemption from the proposed Policy and continue case-by-case BTA determinations (baseline).
2. Regulate nuclear-fueled and conventional facilities in the same manner.
3. Maintain uniform performance standards but establish alternative compliance options for nuclear-fueled facilities with longer implementation schedules than for conventional facilities. Include an explicit provision that defers to NRC requirements if compliance with the proposed Policy compromises safety.

Discussion:
The State's two active nuclear-fueled OTC power plants—Diablo Canyon and SONGS—comprise a significant portion of California's instate electric generating capacity and together provided more than 15% of all electricity generated in the State in 2008.[80] The four individual units at these facilities are licensed to operate through 2022 (SONGS) and 2024 (Diablo Canyon) and are expected to continue as base-load facilities providing electricity to more than four million homes.

Diablo Canyon and SONGS can impinge and entrain substantial numbers of aquatic organisms just by virtue of the sheer volume of cooling water required each day—4.8 BG of cooling water

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[78] 40 CFR. §125.94(f).
[79] See Riverkeeper, Inc. et al. v. U.S. Environmental Protection Agency, (2nd Cir, January 25, 2007) 475 F.3d 83.
[80] US Energy Information Agency, Quarterly Fuel and Energy Reports (QFER), 2008.

per day based on their design capacities (see Section 2 of this document). Because of their status as base-load facilities and corresponding high capacity utilization rates, both Diablo Canyon and SONGS typically withdraw close to their maximum OTC capacity on an annual basis, which accounts for approximately one third of all cooling water withdrawn by the State's coastal OTC facilities. By comparison, the 2005 annual average intake for the 17 fossil-fueled coastal OTC facilities was 9.4 BG per day.[81]

Alternative 1 would exempt Diablo Canyon and SONGS from any further requirements under the proposed Policy and direct the Central Coast and San Diego Regional Water Boards to continue implementing §316(b) on a case-by-case basis using BPJ. This would effectively continue the baseline condition for these facilities and exclude both Regional Water Boards from the benefits that would be gained through the coordinated approach recommended in Section 3.1 of this document. Participation in a statewide effort, for example, would help address many of the issues that have delayed the reissuance of the Diablo Canyon NPDES permit, which was last renewed in 1990 and expired in 1995.

Furthermore, there is no basis to assume the case-by-case BPJ approach that has been in effect for 30 years will yield any better results now than it has in the past. As discussed in Section 2 of this document, State Water Board staff has concluded that impacts associated with OTC operation, including those from Diablo Canyon and SONGS, have not been sufficiently addressed such that they can be considered compliant with §316(b)'s technology-based mandate. Excluding these two facilities would ignore a significant proportion (about a third) of all OTC-related IM/E losses in the State's coastal aquatic communities. Over the coming years, the nuclear-fueled facilities will account for a larger and larger portion of IM/E as more fossil-fueled units are retired or replaced with closed-cycle alternatives.

Alternative 2 would not make any distinction between nuclear and fossil-fueled facilities, subjecting both categories to the same performance standards, compliance alternatives and implementation schedules. While this alternative would ostensibly achieve the proposed Policy's stated goal of reducing IM/E at all facilities, it would ignore relevant differences between the two facility types that could complicate the nuclear-fueled facilities' compliance strategy. Nuclear-fueled facilities are generally more complex than a typical natural gas facility, and must incorporate auxiliary and backup systems to comply with NRC safety regulations. By this fact alone, compliance will likely require additional time so that the needs of all interested parties are met.

Alternative 3 acknowledges the differences between nuclear and conventional-fueled facilities that would not be addressed by Alternative 2 while improving upon the case-by-case BPJ-based approach that would be continued under Alternative 1. The State Water Board recognizes that nuclear-fueled facilities are subject to more stringent regulatory requirements, particularly those of the NRC, which will require additional time to consider and address. The proposed Policy includes language similar to the Phase II rule that defers to the NRC if compliance would conflict with safety requirements. Furthermore, the outsized importance of Diablo Canyon and SONGS to the State's electrical system warrants closer consideration of secondary impacts (e.g., greenhouse gas emissions) that could be significant due to their size. To this end, the proposed Policy includes requirements for nuclear-fueled facilities to fund third party feasibility studies that will evaluate alternative requirements in greater detail, including costs.

[81] Steinbeck, Compilation of California Coastal Power Plant Entrainment and Impingement Estimates for California State Water Resources Control Board Staff Draft Issue Paper on Once-through Cooling, 2008.

Staff Recommendation:
Staff recommends Alternative 3. This alternative preserves the primary goal of protecting the State's coastal ecosystems by limiting OTC's impacts, but acknowledges the unique challenges nuclear-fueled facilities face by allowing additional time to comply with the proposed Policy's requirements.

Policy Section(s):
Appendix A, Section 2.D (*Requirements for Existing Power Plants—Nuclear-Fueled Power Plants*)
Appendix A, Section 3.D (*Implementation Provisions—Special Studies*)

3.4 SHOULD ALTERNATIVE REQUIREMENTS BE ESTABLISHED FOR LOW CAPACITY UTILIZATION FACILITIES?

A measure of a power plants' overall utilization is the capacity utilization rate (CUR). The Phase II rule defined the CUR as the ratio between the average annual net generation of energy by the facility (in MWh) and the total net capability of the facility to generate energy (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, the CUR may be calculated separately for each intake structure, based on the capacity utilization of the units it serves. Phase II 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 steam as the thermodynamic medium, i.e., stand-alone combustion turbines were included in the calculation. Table 10, below, summarizes OTC power plant energy generation capacities by intake structure (e.g., Alamitos Units 1 and 2 are served by the same intake structure).

Phase II exempted units with a CUR of less than 15% from complying with the entrainment performance standard and only required impingement mortality controls. For the purposes of this document, the Phase II CUR definition was used to calculate utilization for all OTC power plants. For combined-cycle power plants, USEPA's definition states that the energy generated and capacity of the combustion turbine should be neglected (i.e., only use the steam turbine heat recovery energy/capacity). However, CEC staff suggested that combined-cycle systems should be considered one distinct generating unit since it reflects the overall efficiency gains on a per unit fuel basis. Capacity and generating output, therefore, are presented as the sum of all components in Tables 10 and 11, below.

Table 10. OTC Power Plant Energy Generation Capacities by Intake Structure

Facility/Units	Generation Technology	Capacity (MW)[a]
Alamitos Units 1&2	ST	350
Alamitos Units 3&4	ST	640
Alamitos Units 5&6	ST	960
Contra Costa	ST	680
Diablo Canyon	N	2269
El Segundo Units 1&2	ST	350
El Segundo Units 3&4	ST	670
Encina Units 1-5	ST	929

Facility/Units	Generation Technology	Capacity (MW)[a]
Harbor	CC	240
Haynes Units 1&2	ST	444
Haynes Units 5&6	ST	682
Haynes Units 9&10	CC	575
Huntington	ST	880
Mandalay	ST	430
Morro Bay	ST	1002
Moss Landing Units 1-4	CC	1020
Moss Landing Units 6&7	ST	1509
Ormond	ST	1500
Pittsburg Units 5&6	ST	650
Potrero	ST	207
Redondo Units 5&6	ST	350
Redondo Units 7&8	ST	963
Scattergood	ST	803
SONGS Unit 2	N	1123
SONGS Unit 3	N	1109
South Bay	ST	690

Notes:
a. Capacities provided by CEC
ST = Steam Boiler, CC = Combined-Cycle, N = Nuclear.

Phase II defines a peaking facility as a power plant with an annual CUR of 15% or less[82]. Per USEPA's definition, CURs were averaged among units served by the same intake structure. By that definition, for example, the CUR for Alamitos Units 1 and 2 is the MWh-weighted average of the CUR of each unit taken separately.

Table 11, below, summarizes the 2005 and 2006 annual averages and the 2000-2005 long-term average CURs for coastal OTC power plants.

Table 11. Capacity Utilization Rates of OTC Power Plants

Facility/Units	2005 CUR (%)	2005 USEPA Peaker	2000-2005 CUR (%)	2000-2005 USEPA Peaker [a]	2006 CUR (%)
Alamitos Units 1&2	3	Yes	9	Yes	3
Alamitos Units 3&4	8	Yes	30	No	13
Alamitos Units 5&6	10	Yes	30	No	10
Contra Costa	6	Yes	28	No	2
Diablo Canyon	89	No	85	No	96

[82] 69 FR 4616 (No. 131).

Facility/Units	2005 CUR (%)	2005 USEPA Peaker	2000-2005 CUR (%)	2000-2005 USEPA Peaker [a]	2006 CUR (%)
El Segundo Units 1&2	--	--	10	Yes	--
El Segundo Units 3&4	12	Yes	27	No	11
Encina Units 1-5	24	No	36	No	15
Harbor	14	Yes	26	No	9
Haynes Units 1&2	21	No	31	No	--
Haynes Units 5&6	10	Yes	18	No	--
Haynes Units 9&10	47	No	47	No	--
Huntington Beach	20	No	21	No	15
Mandalay	10	Yes	34	No	8
Morro Bay	4	Yes	23	No	6
Moss Landing Units 1&2	49	No	38	No	29
Moss Landing Units 6&7	4	Yes	30	No	6
Ormond Beach	4	Yes	22	No	4
Pittsburg Units 5&6	10	Yes	29	No	6
Potrero	22	No	44	No	29
Redondo Beach Units 5&6	1	Yes	7	Yes	2
Redondo Beach Units 7&8	5	Yes	26	No	6
Scattergood	16	No	25	No	21
SONGS unit 2	90	No	89	No	68
SONGS unit 3	98	No	89	No	69
South Bay	27	No	30	No	16

Note: a. Defined as operating at 15% or less of design capacity.

Figure 12 shows the annual OTC energy produced by generation technology for 2000-2005. The energy produced using steam boiler technology is trending downward, while the energy generated using combined-cycle technology is trending upward, and the energy generated using nuclear technology is relatively constant for the time period. These trends are expected to continue as more conventional steam boilers are retired or repowered and replaced with combined-cycle technologies. The State's nuclear capacity is not expected to change in the foreseeable future.

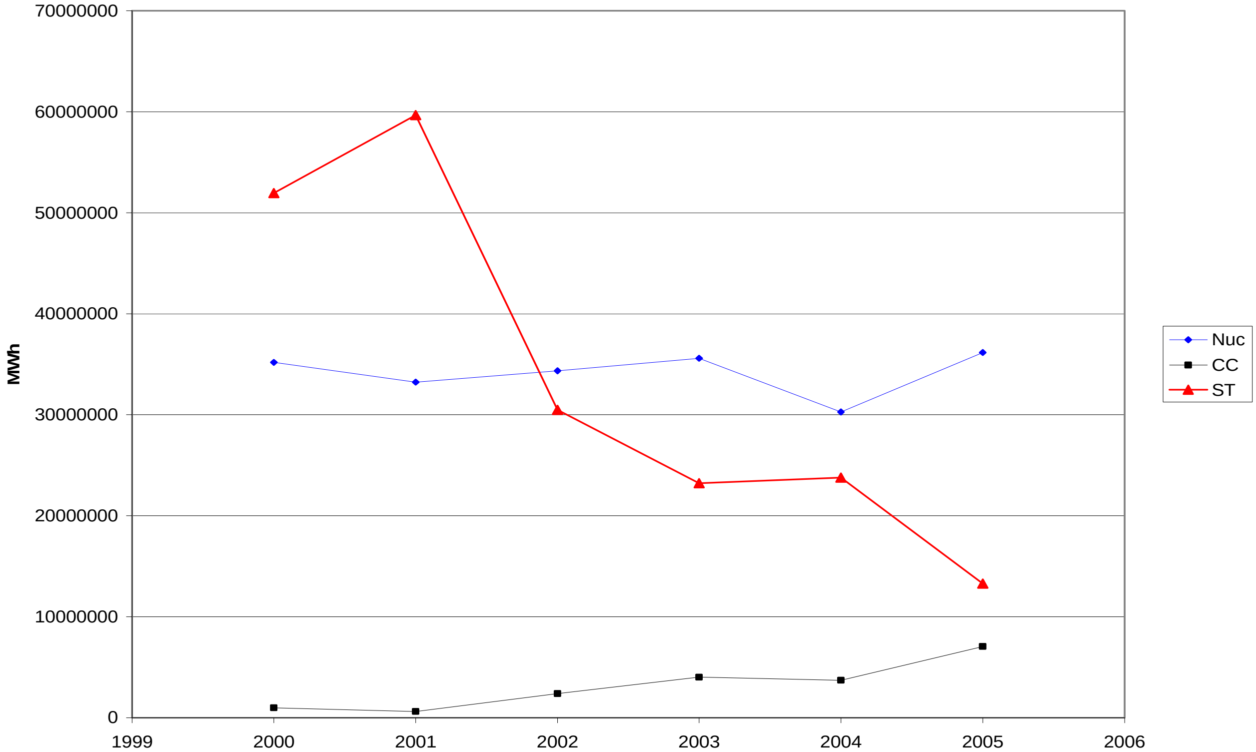

Figure 12. OTC Energy Generation by Technology

Baseline:
Current BPJ-based permitting does not explicitly distinguish between low and high capacity utilization facilities.

Alternatives:

1. Establish alternative requirements for low capacity (<15%) units.
2. Make no distinction based on capacity utilization (baseline).

Discussion:
A facility's CUR is not necessarily indicative of the impact it may have on the aquatic environment since the potential for harm is not equally distributed throughout the year, particularly for entrainment; spawning typically peaks in spring and early summer throughout the state. Figure 13 and Figure 14, below, reproduced from the 2008 Steinbeck report (which was approved by the ERP), show the seasonal variation in larval fish concentrations per cubic meter (m^3) at southern and northern OTC facilities.

Alternative 1 would establish alternative, less stringent criteria for low CUR facilities based on the false assumption such facilities cause appreciably less harm than a high capacity facility. Data show, however, that it is possible to operate less than 15% of the time and cause a greater impact than would be assumed if entrainment was uniform at all times. Alternative 2 would not make any distinction between facilities based on their capacity utilization rates. This is appropriate since there is no definitive correlation between capacity utilization and adverse impact.

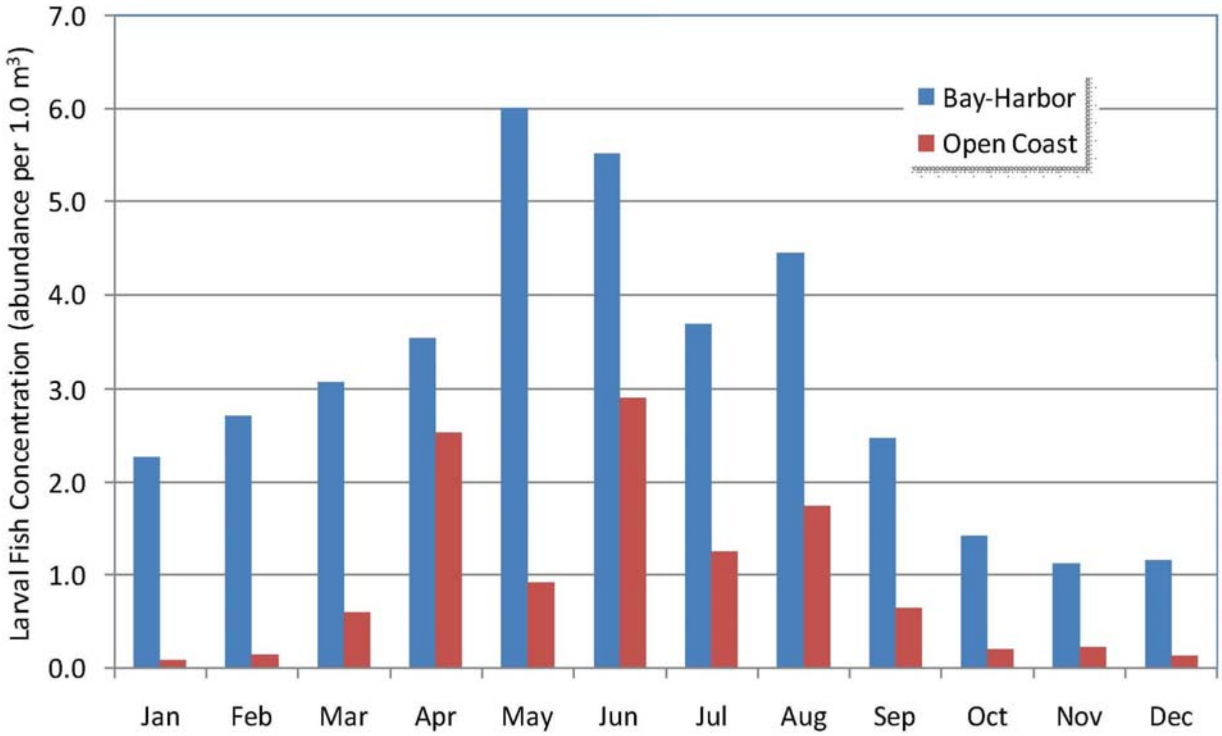

Figure 13. Larval Fish Concentrations at Southern OTC Facilities

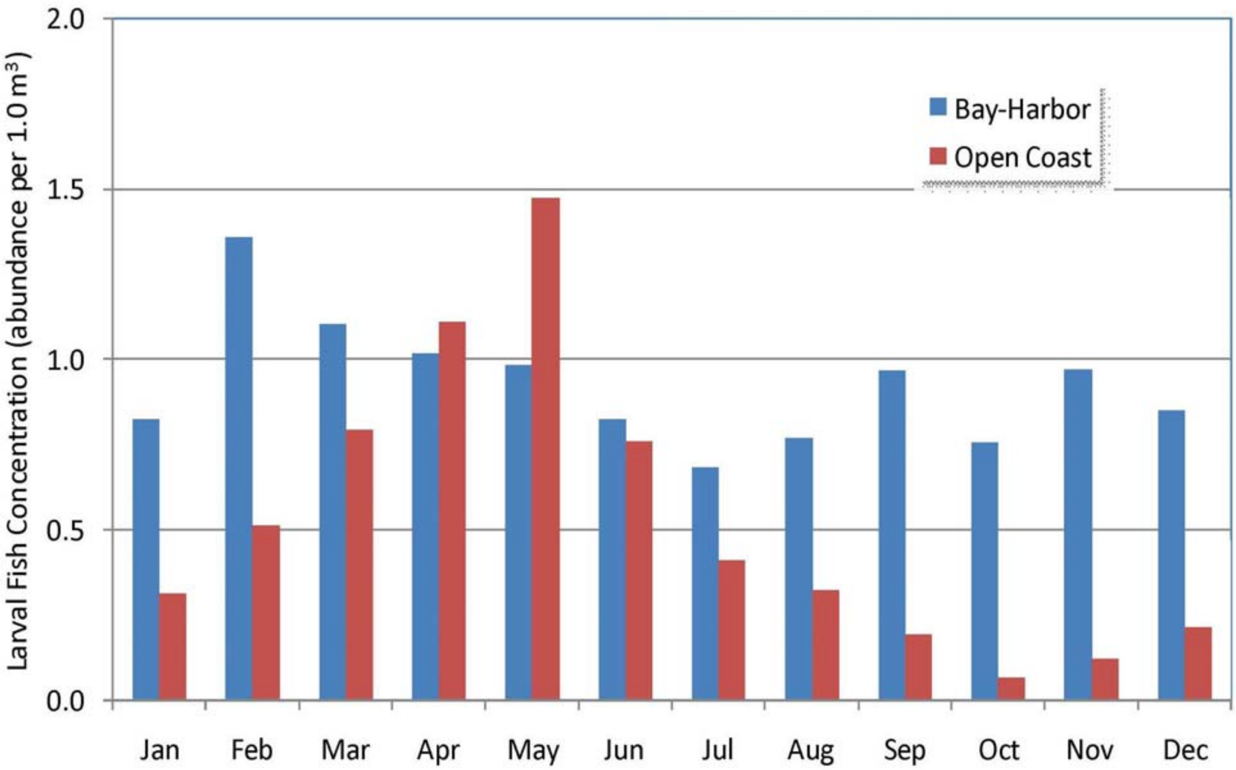

Figure 14. Larval Fish Concentrations at Northern OTC Facilities

Staff Recommendation:
Staff recommends Alternative 2.

Policy Section(s):
Not applicable.

3.5 SHOULD THE PROPOSED POLICY ADDRESS DESALINATION FACILITIES?

Seawater desalination increasingly supplements municipal water supplies in coastal California communities. New desalination technologies have made desalination more feasible and cost-effective, but remain energy-intensive processes that produce high-salinity waste brine that must be disposed of. Waste brine can be twice the salinity of the seawater used to produce it and, given its greater density, has the potential to sink to the ocean bottom and adversely impact sensitive benthic organisms if discharged without diffusion, undiluted, and in high volumes.

Many desalination facilities constructed or proposed along California's coast are co-located at or near existing OTC power plants. The desalination facility benefits by using a portion of the seawater withdrawn by an existing intake structure without having to construct a new, independent intake. Co-location also enables the desalination facility to co-mingle its brine discharge with the power plant's large cooling water volumes, thus ensuring adequate dilution prior to final discharge to the receiving water.

Baseline:
Desalination facilities are subject to existing NPDES requirements for intakes and discharges to surface waters and must apply for an NPDES permit. Currently, there are no state or federal regulations that specifically apply to desalination intakes.

Alternatives:
1. Include provisions for desalination facilities.
2. Address all desalination facilities through another policy.

Discussion:
Alternative 1 would apply the proposed Policy to all desalination facilities, but would require substantial revisions to the Policy's basis and compliance alternatives. §316(b) is applicable only to "cooling water intake structures," which USEPA has defined as the total physical structure used to withdraw water from a surface water, at least 25% of which is used for cooling purposes.[83] Desalination facilities do not exceed this threshold and would not be subject to any of USEPA's existing or proposed regulations. The proposed Policy, therefore, would need to include a separate policy basis.

Desalination facilities and OTC thermal power plants are fundamentally different in their use of intake water, thus the means by which BTA would be determined is also very different. For existing OTC power plants, the most effective technology is closed-cycle wet cooling, which reuses a small volume of water several times to achieve the desired cooling effect. Desalination, on the other hand, is an extractive process for which the volume of water used cannot be limited without impairing the final production.

[83] 40 CFR §125.81

Alternative 2 would reserve the desalination issue for another mechanism outside of the proposed Policy. Most coastal desalination facilities, depending on when they were first constructed, are subject to Cal. Wat. Code §13142.5(b), which applies to all "new or expanded coastal…industrial installations using seawater for cooling, heating, or industrial processing" and requires the minimization of the intake and mortality of all marine life.

Staff Recommendation:
Staff recommends Alternative 2: Address all desalination facilities through another policy. By limiting the proposed Policy to OTC facilities only, the State Water Board can most effectively address the unique characteristics of the coastal OTC power plants. Desalination facilities are more appropriately addressed in a separate plan or policy.

Policy Section(s):
Not applicable.

3.6 WHAT CONSTITUTES BTA FOR EXISTING POWER PLANTS?

The CWA prohibits the point source discharge of pollutants to waters of the United States except as authorized. CWA §402 establishes the NPDES permitting program to regulate such discharges by developing specific effluent limitations that are then incorporated into a facility's NPDES permit. CWA §§ 301, 304 and 306 direct the permitting authority to develop limitations based on the technologies available to treat a certain pollutant ("technology-based") or, where technology-based limits are insufficient to meet water quality standards, develop more stringent limitations that protect the beneficial uses of a particular receiving water ("water quality-based"). For technology-based limits, a permit writer may use nationally developed Effluent Limitation Guidelines (ELGs) that establish reasonable performance standards for a particular industrial category and achieve a minimum level of treatment or protection. In the absence of ELGs, the permit writer is directed to use the same performance-based approach to support a BPJ assessment on a case-by-case basis.

CWA §316(b) is somewhat unique among the CWA's provisions in that it addresses adverse environmental impacts caused by withdrawing water through an intake structure rather than limiting impacts caused by discharges into a receiving water. The provision's BTA standard—best technology available for minimizing adverse environmental impact—is not defined nor does the statute provide any further guidance as to how it should be evaluated. USEPA has instead looked to other sections (CWA §§301, 304, and 306) for guidance in determining what factors may be used in a BTA analysis, an approach that has been upheld in the *Riverkeeper I* and *II* decisions.

For example, when evaluating "best available technology" (different from BTA), CWA §304 directs the permitting authority to consider

> the age of equipment and facilities involved, the process employed, the engineering aspects . . . of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impacts (including energy requirements), and such other factors as [EPA] deems appropriate.[84]

[84] 33 U.S.C. § 1314(b)(2)(B).

USEPA's Phase I rule and subsequent efforts can be considered similar to the technology-driven ELG process in that they seek to develop national standards based on reasonably achievable performance. Absent a national standard, permitting authorities are directed to substitute BPJ but follow a similar process based on technology performance. Guidance for the BPJ approach is limited, however, and has often led to BTA determinations that are influenced by the relative scale of any impacts to the source water—a "population effects" basis—rather than the technology-driven standard mandated by the statute. The *Riverkeeper II* decision reiterated the Second Circuit's opinion that, because it is a technology-driven statute, §316(b) need not be implemented by first considering the extent of any impact before determining BTA.[85] The *Entergy* decision did not address this topic.

A key distinction between USEPA's §316(b) regulations, particularly in Phase II, and those developed under §301 or §306 has been the consideration of costs relative to benefits before making a final BTA determination. The *Entergy* decision upheld this approach as a reasonable interpretation of the statute, although it explicitly noted that a cost-benefit comparison is not required under §316(b); a BTA determination can be made without it.

Other portions of the *Riverkeeper II* decision relating to BTA that were not overturned in *Entergy* remain relevant and provide guidance for the State Water Board's development of the proposed Policy. First, costs may be considered insofar as they can be "reasonably borne" by the industry or when evaluating the cost-effectiveness of two similarly performing technologies. Second, the BTA standard is technology-driven and cannot include restoration, which compensates for an adverse impact after it as occurred rather than minimizing its occurrence in the first place. Third, BTA must be based on the "best" technology available (i.e., "optimally best performing") rather than an average of a technology's performance across multiple facilities. Lastly, secondary impacts may also be considered, such as secondary environmental effects and decreased energy production and efficiency.

Baseline:
BTA for all of the State's coastal OTC power plants is determined by the respective Regional Water Board using BPJ on a case-by-case basis.

Alternatives:

1. Establish BTA as an intake flow rate reduction at each unit to a level commensurate with a closed-cycle wet cooling system and a through-screen intake velocity reduction to no more than 0.5 ft/sec (Track 1). Alternatively, the facility must reduce IM/E to a level comparable to Track 1 for the facility, as a whole, through operational and structural controls, or both (Track 2).
2. Establish BTA as an intake flow rate reduction at each unit to a level commensurate with a closed-cycle dry cooling system (Track 1). Track 2 would be similar to Alternative 1; the facility would need to reduce IM/E to a level comparable to a closed-cycle dry cooling system and a through-screen intake velocity reduction to no more than 0.5 ft/sec through operational and structural controls, or both.
3. Establish BTA as an intake flow rate and velocity reduction for all facilities as defined in Alternative 1 under Track 1. Track 2 would not be available.

[85] See Riverkeeper, Inc. et al. v. U.S. Environmental Protection Agency, (2nd Cir, January 25, 2007) 475 F.3d 83.

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

Discussion:
Alternative 1
This alternative establishes BTA based on entrainment reductions that can be achieved when an OTC facility retrofits to a closed-cycle wet cooling system. For impingement mortality, BTA is based on reducing the through screen intake velocity to no more than 0.5 ft/sec. Both provisions are based on measured performance at other facilities as well as case study evaluations of wet cooling system retrofits by USEPA, the State Water Board, academic institutions and industry organizations.

Reducing a facility's intake capacity is the most effective and certain method by which entrainment can be reduced and is expressly permitted under §316(b) as one of four areas that may be regulated under the statute (design, construction, capacity and location). Entrainable organisms, such as eggs and larvae, are generally free-floating and do not have the capacity to escape an intake structure's influence like juvenile and adult fish. Among industry and regulatory agencies alike, it is an accepted premise that the number of organisms entrained is more or less proportional to the water volume withdrawn through the intake structure during a limited time period. It is reasonable, therefore, to assume that reducing a facility's intake capacity will similarly reduce the total entrainment as well.[86] Although entrainment reductions are the primary achievement when intake flow is reduced, impingement rates are also likely to decrease, largely due to a substantially smaller intake volume that is withdrawn through the same intake structure, i.e., reducing through-screen velocity.

The percentage reduction a facility can achieve when converting from OTC to a closed-cycle wet cooling system is dependent on several factors, including climate conditions, condenser design and the source water quality used to provide makeup water to the cooling towers. In general, however, the reduction can be reasonably estimated based on the maximum dissolved solids concentration permissible in the circulating water, or cycles of concentration. A reference to "1.5 cycles of concentration" means that the circulating water in the tower is allowed to reach a dissolved solids concentration no more than 50% higher than the source water. To maintain this level, a portion of the circulating water must continually be purged and replenished, also known as blowdown and makeup water. Higher cycles of concentration typically correspond to lower makeup water demands, i.e., a higher flow reduction versus OTC. As shown for the example facility in Figure 15, flow reductions vary most significantly between 1 and 2 cycles of concentration.

This alternative adopts a minimum intake flow rate reduction of 93% compared to the OTC capacity. In its report prepared for the Ocean Protection Council, TetraTech developed closed-cycle wet cooling tower configurations for most of the State's coastal OTC facilities using 1.5 cycles of concentration, which translates to intake capacity reductions ranging from 93-97% of the original OTC flow.[87] An independent analysis of the same facilities prepared by EPRI used

[86] USEPA, Technical Development Document for the Proposed 316(b) Phase II Existing Facilities Rule. 2002.
[87] Tetra Tech, 2008.

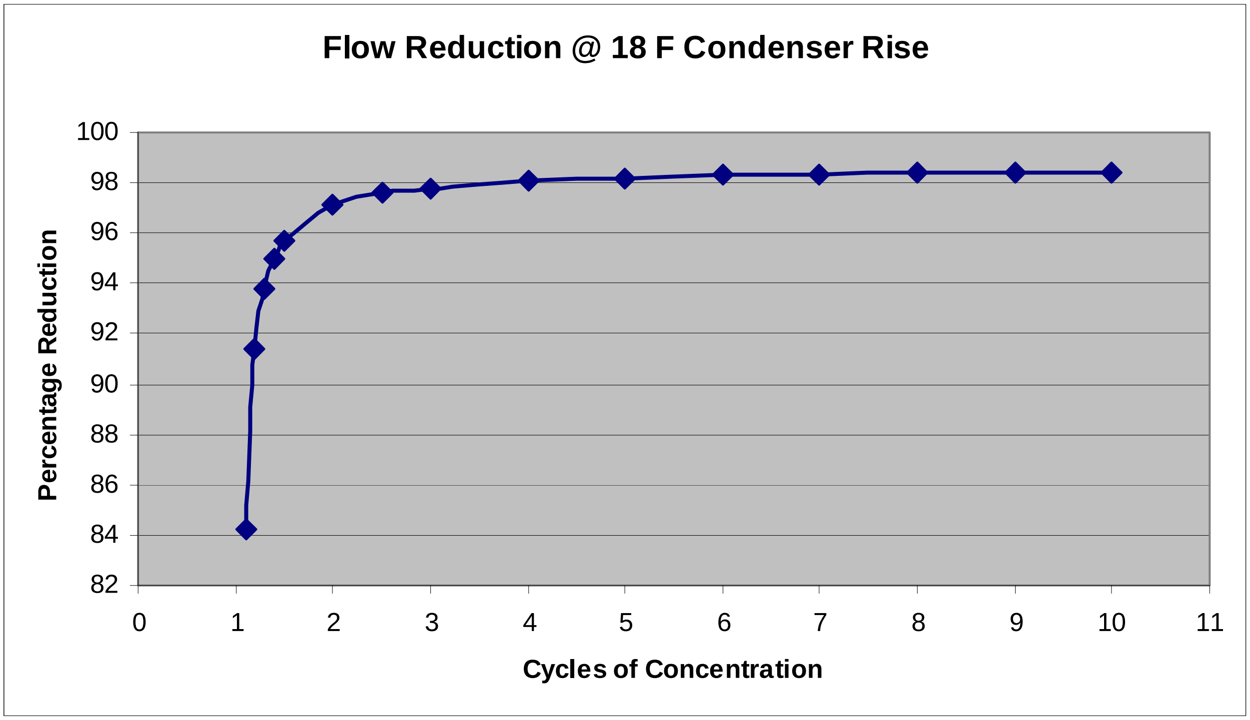

Figure 15. Flow Reductions at Different Cycles of Concentration

a similar design basis and reached the same overall flow reduction estimates.[88] Flow reductions, however, can vary from facility to facility depending on their original intake flow capacity and other design factors. For this reason, Alternative 1 adopts the lower bound (93%) as the performance standard for entrainment.

The basis for the entrainment performance standard—closed-cycle wet cooling—must meet the criteria established for determining BTA. In short, the technology must be “available” in the sense that it is technically and logistically feasible at most facilities subject to the proposed Policy, and must be an economically viable method for addressing the Policy’s stated goals. The significance of any secondary impacts associated with compliance must also be considered before a final determination can be made.

Alternative 1 establishes a specific impingement mortality performance standard limiting through-screen intake velocity to no more than 0.5 ft/sec. Intake velocity is a critical factor influencing the rates at which motile fishes are able to detect and escape the physical pull of the intake pumps. The 0.5 ft/sec threshold is based on numerous swim speed studies and has been used in several federal regulations, including the Phase I rule.[89] Through screen velocity reductions can be achieved by reducing the intake volume or by expanding the total through-screen area.

A retrofitted facility, for the purposes of this document, is one in which a power plant replaces its OTC system with alternate cooling technologies without making any changes to the existing power generating system (boilers, turbines, etc.). Depending on the technology used in the

[88] EPRI, 2007.
[89] 66 FR 65274 (No. 243)

retrofit (wet cooling towers, for example), the facility may suffer performance penalties because its existing systems were not designed to optimally operate at the higher circulating water temperatures. These performance penalties are exacerbated if the retrofit technology was dry cooling, potentially rendering the facility inoperable under certain climate conditions. In this case, the additional intake flow reductions that could be achieved with dry cooling (2-3%) are not justified by the significantly greater costs compared to wet cooling.[90]

A re-powered facility, on the other hand, while not a new facility, is similar in that it is better equipped to incorporate a dry cooling system from the start and address any anticipated performance penalties by redesigning critical system components. Newer technologies such as combined-cycle generation, which generates more electricity per unit of fuel and requires less cooling water per MWh of capacity, are more amenable to incorporating dry cooling. In fact, most new generation projects in California use dry cooling, including the re-powering projects at Humboldt Bay, El Segundo, Encina, and Long Beach. Dry cooling at power generating units does not use water for cooling purposes and will therefore eliminate IM/E. Dry cooling therefore meets the Alternative 1 condition “at a minimum to a level commensurate with a closed-cycle wet cooling system” because it exceeds the minimum of 93% reduction in intake flow rate. The installation of closed-cycle dry cooling systems thus meets the intent and minimum reduction requirements of this compliance alternative.

Alternative 1 Basis

The Tetra Tech report evaluated the technical and logistical feasibility of retrofitting 15 of the State’s coastal OTC facilities with closed-cycle wet cooling systems.[91] The report developed conceptual retrofit designs based on each facility’s design parameters and evaluated feasibility in terms of logistics (e.g., available space, interference with other critical systems or nearby infrastructure), operations (e.g., energy penalty), local use restrictions (e.g., noise or building codes) and aesthetic or environmental restrictions (e.g., conflicts with conservation plans, impacts to threatened and endangered species). Tetra Tech also prepared a 20-year cost estimate based on the conceptual design but did not evaluate feasibility based on cost.

The Tetra Tech report found that closed-cycle wet cooling is technically and logistically feasible at 12 of the 15 facilities that were part of the study (Alamitos, Contra Costa, Diablo Canyon, Harbor, Haynes, Huntington Beach, Mandalay, Morro Bay, Moss Landing, Pittsburg, SONGS, and Scattergood). Three facilities did not meet the feasibility threshold (Redondo Beach, Ormond Beach, and El Segundo).

Retrofitting the State’s two nuclear-fueled facilities is problematic, although not infeasible according to the Tetra Tech report criteria. At Diablo Canyon, sufficient space is available but will require relocating other facility infrastructure (parking, maintenance shops, etc.) to other areas. Space is less of a concern at SONGS, but its location immediately adjacent to a state beach and sensitive coastal bluffs, as well as its tenant relationship with the Camp Pendleton Marine Corps base, add to the likelihood that the approval process would be lengthy. Each facility would also have to shut down its operations for months to integrate the new cooling system into the existing facility. At SONGS, Units 2 and 3 can be taken offline separately since each essentially operates as an individual unit. Diablo Canyon, however, cannot stagger implementation because Units 1 and 2 share a common intake structure, which precludes continued operation of one unit while simultaneously retrofitting the other unit’s cooling system.

[90] CEC. Comparison of Alternate Cooling Technologies for California Power Plants: Economic, Environmental and Other Tradeoffs. 2002. 500-02-079F. February 2002.
[91] Tetra Tech did not develop an assessment for the South Bay, Humboldt Bay, Potrero and Encina Power Plants because of stated plans to cease OTC operation in the near future.

Lastly, any system modifications would require approval by the NRC to ensure compliance with all relevant safety standards. While maintaining the same performance standards for nuclear-fueled facilities, the proposed Policy addresses these complicating factors by including alternative compliance options and requirements.

The Tetra Tech report considered El Segundo infeasible because there was insufficient space on which to site the necessary plume-abated cooling towers for all four units. El Segundo's proximity to the Los Angeles International Airport and neighborhoods in Manhattan Beach made it likely that a visual plume would be unacceptable at that location. State Water Board staff notes, however, that since the report was published, El Segundo has begun construction on a repowering project to replace Units 1 and 2 with dry cooling. Sufficient space might now be available to retrofit the remaining two units (Units 3 and 4).

Likewise, the Tetra Tech report considered Ormond Beach infeasible due to insufficient space for plume-abated cooling towers. The facility is located only 2.5 miles west of the Point Mugu Naval Air Station, increasing the possibility that a visual plume might interfere with flight operations and require plume abatement, although this could not be confirmed. Conservation easements and the proximity to state beaches limit the possibility that Ormond Beach could obtain sufficient land elsewhere.

Retrofitting to wet cooling towers is not feasible at Redondo Beach because of its centralized location in the heart of Redondo Beach. Tetra Tech could not develop a conceptual layout that would meet local use restrictions for noise, building height and aesthetic impacts (visual plume). Nearby office buildings and ongoing redevelopment projects make it unlikely any wet cooling tower—plume-abated or not—could be approved at this location at the size required to replace the existing intake capacity.

Under Alternative 1, the State Water Board does not conduct a cost-benefit assessment to establish BTA. Although the *Entergy* decision authorized cost-benefit as one factor that *may* be considered under §316(b), State Water Board staff does not believe cost-benefit is appropriate at the programmatic level. Instead, State Water Board staff evaluated whether the costs of compliance under Alternative 1 could be "reasonably borne" by the affected industry.

As shown in Table 12, reproduced from the Tetra Tech report, the 20-year annualized cost translates to $4.48/MWh (0.45 cents/kWh) based on the maximum possible output (rated capacity). As most conventional steam facilities operate at substantially lower rates, a more accurate cost may be $11.34/MWh (1.13 cents/kWh), based on 2006 capacity utilization rates.

<u>*Two Track Approach*</u>

The Tetra Tech report satisfies the requirement to assess feasibility at the programmatic level, taking into account site-specific factors such as 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. While the report supports State Water Board staff's basis for establishing BTA based on closed-cycle wet cooling, the proposed Policy recognizes that additional site-specific factors may make intake flow rate reductions infeasible at a particular site when a more detailed analysis is conducted. For this reason, the proposed Policy allows for a two track approach to determine BTA at each location.

Using Track 1, a facility would install design and construction technologies or certify operational changes that consistently reduce the unit-by-unit intake flow rate by 93% or more compared to OTC. In addition, the facility would need to demonstrate that it has implemented design and construction technologies or instituted operational changes that reduce the through-screen velocity to no more than 0.5 ft/sec. Track 1 is a streamlined approach that allows a facility to easily demonstrate an acceptable IM/E reduction without the added burden of continually monitoring the technology's performance and conducting future studies. The Regional Water Board's burden is also lessened substantially in that it will not have to continually verify the facility's IM/E reductions or engage in a detailed analysis of alternative compliance measures.

Table 12. Annualized Cost—Alternative 1

Facility category	20-year total annualized cost [a],[b] ($)	Rated capacity (GWh)	Cost per MWh ($/MWh) for rated capacity	2006 net output (GWh)	Cost per MWh ($/MWh) for 2006 net output
Nuclear [c]	442,600,000	39,017	11.34	35,603	12.43
Steam turbine [d]	123,400,000	75,257	1.64	8,522	14.48
Combined-cycle [e]	20,600,000	16,557	1.25	7,613	2.72
All facilities	**586,600,000**	**130,831**	**4.48**	**51,738**	**11.34**

[a] 20-year annualized cost of all initial capital and startup costs, operations and maintenance, and energy penalty. Value represents the total annualized cost for all facilities in each category.

[b] 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:	$ 2 million

[c] Diablo Canyon and San Onofre

[d] Alamitos, Contra Costa, El Segundo (Units 3 & 4 only), Haynes (Units 1, 2, 5, & 6 only), Huntington Beach, Mandalay, Moss Landing (Units 6 & 7 only), Pittsburg, and Scattergood.

[e] Harbor, Haynes (Unit 8 only), and Moss Landing (Units 1 & 2 only).

GWh = gigawatt hour

MWh = megawatt hour

While Track 1 is intended to require compliance on a unit-by-unit basis, Track 2 permits a facility as a whole to use alternative means to achieve an IM/E reduction that is the same or comparable to the Track 1 reduction, which is defined as no less than 90% of the IM/E reduction in Track 1. A facility would be able to use any combination of design and construction technologies and/or operational measures that achieve the desired reductions (e.g., using recycled treated wastewater, fine mesh screens, variable speed pumps, or seasonal restrictions). Any performance claims would have to be verified through an ongoing self-monitoring program subject to the Regional Water Board's approval. Credit may be taken for other technologies and/or operational measures if they were implemented prior to the effective date of the proposed Policy with the explicit intent of reducing IM/E.

The determination of comparability to Track 1 would be dependent on the specific Track 2 controls. For plants relying solely on reductions in velocity, compliance for impingement mortality would be determined by monthly verification of through-screen intake velocity at each plant intake, not to exceed 0.5 ft/sec. For other structural or operational controls, compliance for impingement mortality would be determined by monitoring. For measured reductions determined by monitoring, the owner or operator would need to reduce impingement mortality to a comparable level to that which would be achieved under Track 1. In this case a "comparable level" is a level that achieves at least 90% of the reduction in impingement mortality required under Track 1.

For plants relying solely on reductions in flow, compliance for entrainment would be determined by recording and reporting reductions in terms of flow, in which case a minimum of 93% reduction in terms of design flow must be met. The ERP had a clear preference for using entrainment-weighted flow. In their final responses (July 31, 2008) the ERP stated: "reductions should be based on larval abundance, not simply flow, and larval abundance should be weighted (monthly?) based on temporal variation." Therefore, State Water Board staff has determined that when Track 2 plants rely solely on reductions in flow, flow should be reported in terms of monthly flow. While not identical to requiring entrainment-weighted flow measurements, this essentially serves the same purpose since entrainment is essentially a function of flow and month of the year (see Figures 13 and 14 in Section 3.4, above).

For plants relying in whole or in part on other control technologies (e.g., screens), compliance for entrainment would be determined by measured reductions in entrainment determined by monitoring. For measured reductions in entrainment determined by monitoring, the owner or operator must reduce entrainment to a comparable level to that which would be achieved under Track 1. In this case a "comparable level" is a level that achieves at least 90% of the reduction in entrainment required under Track 1.

The draft version of this document, and its Appendix A draft policy (July 2009), contained a provision that if a facility demonstrates that Track 1 is infeasible to the Regional Water Board's satisfaction, it would then be able to comply with BTA through Track 2. Based on consideration of public comment received since then, State Water Board staff is recommending the removal of an "infeasibility test." Staff believes the determination of infeasibility will be problematic and subjective, likely resulting in inconsistencies from Region to Region, and at the very least would burden the Regional Water Boards with an unnecessary additional workload.

As one hypothetical example of using Track 2, a facility may re-power two of its four units using dry cooling, and then limit the once-through cooling at the remaining two units to allow only a maximum of 7% IM/E of the facility's baseline overall. This would result in 93% reduction in IM/E on a facility basis, which would result in the same minimum reduction in IM/E as in Track 1. There are many more potential approaches using combinations of closed cycle wet cooling, dry cooling, other design and construction technologies, and/or operational measures too numerous to include here. However, Track 2 allows the operators the flexibility to propose individual site-specific strategies to achieve results comparable to Track 1.

State Water Board staff recognizes existing combined-cycle units as special cases requiring alternative requirements. Existing combined-cycle units are generally very energy efficient, produce lower air emissions for most pollutants and carbon dioxide, are more efficient in water use and therefore have fewer OTC impacts relative to electricity generated, and represent relatively recent capital expenditures. For these reasons, providing alternate requirements under Track 2 of the policy for combined cycle units, and plants where those units are located, would result in better statewide consistency and would reduce the burden on Regional Boards. The alternative Track 2 requirements for combined-cycle units are discussed in Issue 3.13 below.

<u>Alternative 2</u>

This alternative maintains the same framework as Alternative 1, but establishes a more stringent BTA. Intake flow rate reductions would be based on closed-cycle <u>dry</u> cooling (Track 1) rather than <u>wet</u> cooling. Dry cooling at power generating units would reduce IM/E to zero (i.e., a 100% reduction in intake flow rate), and thus make this alternative the most protective of marine life. In this alternative, closed-cycle wet cooling would not meet the definition of BTA. Track 2 would nominally remain the same as described in Track 1, except that a facility as a whole would need to have a comparable level of control to closed-cycle dry cooling (i.e., a 100% reduction in intake flow rate), which is a virtually impossible alternative.

As in Alternative 1, the draft version of this document (July 2009), contained a provision in Alternative 2 that if a facility demonstrates that Track 1 is infeasible to the Regional Water Board's satisfaction, it would then be able to comply with BTA through Track 2. Based on consideration of public comment received since then, the "infeasibility test" by the Regional Board has been removed from this alternative.

State Water Board staff recognizes that some facilities may be incapable of complying with closed-cycle dry cooling as BTA. In addition, retrofitting steam boiler units using dry cooling would result in slightly lower fuel efficiencies and therefore more air pollution. For these reasons staff does not recommend limiting BTA to only dry cooling.

Alternative 3
This alternative would retain the performance standards in Alternative 1 (intake flow rate reductions commensurate with closed-cycle wet cooling and intake velocity to no more than 0.5 ft./sec) but would limit BTA determinations to Track 1 only; Track 2 would not be available. State Water Board staff recognizes that some facilities may be incapable of complying with Track 1 (e.g., Redondo Beach) and cannot unreasonably restrict compliance when alternative methods are available that can achieve similar performance. Without Track 2, the proposed Policy might force facilities to shut down if the necessary permits are not issued. Conversely, by limiting BTA to Track 1 only, the proposed Policy might inadvertently continue the existing §316(b) framework by exempting some facilities from any further compliance efforts because the performance standards could not be met using the available compliance measures.

Alternative 4 (Baseline)
This alternative continues the baseline condition by which Regional Water Boards determine BTA using a BPJ-based, case-by-case approach. As stated throughout this document, this method is by far the least desirable alternative in meeting the proposed Policy's stated goals. There is no evidence that the BPJ approach will be more effective in the future versus the past, nor does it achieve the coordinated effort between Regional Water Boards and other state agencies that is necessary to address the complex, interconnected issues this proposed Policy raises.

Staff Recommendation:
Staff recommends Alternative 1: Establish BTA as an intake flow rate reduction at each unit at a minimum to a level commensurate with a closed-cycle wet cooling system and a through-screen intake velocity reduction to no more than 0.5 ft/sec (Track 1). Alternatively, under Track 2, the facility must reduce IM/E to a level comparable to Track I through operational and structural controls, or both. This alternative broadly addresses the proposed Policy's multiple goals (ensuring adequate protection for the State's waters, while reducing the permitting burden for Regional Water Board staff) without being overly restrictive (as in Alternatives 2 and 3) or not restrictive enough (as in Alternative 4). Note that closed-cycle dry cooling is at least as protective of marine life as closed-cycle wet cooling and therefore meets the intent and minimum reduction requirements of Track 1.

Policy Section(s):
Appendix A, Section 2.A (*Requirements for Existing Power Plants -Compliance Alternatives*)

3.7 How is the Track 1 Entrainment Performance Standard Calculated?

Performance standards reflect the State Water Board staff's conclusion that certain technology-based methods for reducing adverse environmental impacts associated with cooling water intake operation are more effective than others without expressly requiring the use of one technology versus another. This maintains a degree of flexibility for the facility to select technology-based measures that are most appropriate to its circumstances. Staff recommends that BTA for reducing entrainment's adverse impacts be an intake flow rate reduction commensurate with closed-cycle wet cooling, or 93% below the current OTC flow rate.

Baseline:
Not applicable. NPDES permits implement §316(b) requirements on a case-by-case basis using BPJ.

Alternatives:

1. State the Track 1 entrainment performance standard as a mandatory entrainment reduction based on the facility's average entrainment over the most recent 5-year period.
2. State the Track 1 entrainment performance standard as a mandatory intake flow rate reduction calculated as a percentage of the facility's design flow.

Discussion:
The design intake capacity of the State's fossil-fueled OTC units is approximately 10.5 BGD, although the recent annual average for these facilities is substantially less. As shown in Table 13, below, many of these units have been in operation for several decades, some for 50 years or more. Over that time period new power plants have been constructed that use more advanced generating technologies and operate more efficiently and cost effectively compared to the older steam OTC units.

Because many of these units used to function as base-load units, with a correspondingly high capacity utilization rate, intake volumes were also higher as a proportion of the unit's intake capacity. The construction of more modern, more efficient power plants, combined with older units' declining efficiencies and deregulation of the electric power industry, have changed the status of many units to that of peaking or intermittent (load-following) generators that operate at a fraction of their boilerplate capacities. Thus, the amount of cooling water used, on an annual basis, has dropped dramatically as well and remains low. Annual water usage (for conventional facilities) is not expected to increase in the future.

Alternative 1 would capture any long-term changes to a facility's annual intake volume by expressing the entrainment performance standard in terms of a percentage reduction using the most recent 5-year average to establish the baseline. A facility would be required to submit adequate documentation detailing the basis for its baseline calculation, subject to review and approval by the Regional Water Board. The technology-based compliance method would likewise be proposed by the facility along with an adequate verification monitoring plan that would be incorporated into the facility's NPDES permit. Verification monitoring would be an on-

Table 13. OTC Flow Information

Facility/Unit	In-service Year(s)	Design Intake Flow (MGD)	2000-2005 Average Flow (MGD)	Average Flow (as Percentage of Design Flow)

Facility/Unit	In-service Year(s)	Design Intake Flow (MGD)	2000-2005 Average Flow (MGD)	Average Flow (as Percentage of Design Flow)
Alamitos Units 1 and 2	1956/1957	207	121	58
Alamitos Units 3 and 4	1961/1962	392	281	72
Alamitos Units 5 and 6	1966/1969	674	413	61
Contra Costa Units 6 and 7	1964	440	257	58
El Segundo Units 3 and 4	1964/1965	399	265	66
Encina	1954-1978	857	621	72
Harbor	1994	108	59	55
Haynes	1962-2005	968	258	27
Huntington Beach	1958*	514	179	35
Mandalay	1959	253	234	92
Morro Bay	1962/1963	668	257	38
Moss Landing Units 1 and 2	2002	361	193	53
Moss Landing Units 6 and 7	1967/1968	865	387	45
Ormond Beach	1971/1973	685	521	76
Pittsburg Units 5 and 6	1960/1961	506	274	54
Potrero	1956	231	193	84
Redondo Units 5 and 6	1954/1957	217	51	24
Redondo Units 7 and 8	1967	675	254	38
Scattergood	1958-1974	495	309	62
South Bay	1960-1964	601	417	69

Note: *Units 3 and 4 were retooled in 2002 and 2003

going requirement necessary to ensure the technology was achieving the mandatory entrainment reduction.

Alternative 2 would ignore any recent flow reduction trends and instead establish a single numeric performance standard that could be applied to all facilities. It is based on the generally accepted assumption that entrainment (and to some extent, impingement) is proportional to the volume of water withdrawn, although the relationship may fluctuate based on species composition, spawning periods, migration patterns, climate conditions and the facility's initial design configuration.

The State Water Board staff concedes the possibility that entrainment reductions might vary slightly from the flow reduction-based estimate but considers them insignificant and acceptable compared to the reduced burden this alternative would place upon both the facility and Regional Water Board. In Track 1, flow reduction, particularly closed-cycle cooling, is a technology-based measure that is easily verifiable and produces certain and consistent entrainment reductions as well. Compliance is determined by verifying the flow/velocity reduction measures have been implemented and does not burden the facility with having to demonstrate the expected entrainment reductions by actively monitoring the intake. USEPA used a similar justification when establishing the Phase II compliance alternative for closed-cycle cooling.[92]

Alternative 2 would not explicitly require an entrainment reduction but would achieve the same desired result by requiring an intake flow that is, at a minimum, 93% less than the facility's design intake flow. This value is based on studies prepared for the State Water Board by Tetra Tech and an independent EPRI report.[93] Both studies estimate flow reductions using reasonable and acceptable industry standards for wet cooling tower designs and conclude that such retrofits would reduce intake volume by a range of 93-96% of the design capacity. In selecting the 93% flow reduction, which is achievable by any retrofitted facility, the policy dramatically streamlines the application and compliance process and eliminates the need to conduct site-specific retrofit evaluations for most facilities.

Staff Recommendation:
Staff recommends Alternative 2: State the Track 1 entrainment performance standard as a mandatory intake flow rate reduction calculated as a percentage of the facility's design flow. This alternative is consistent with the State Water Board's goals of establishing a statewide policy with uniform performance standards that can simultaneously achieve the desired protection of the State's coastal ecosystems.

Policy Section(s):
Appendix A, Section 2.A(1)(*Requirements for Existing Power Plants-Compliance Alternatives*)

3.8 WHAT BASELINE MONITORING SHOULD BE REQUIRED?

Where site-specific information is necessary, facilities subject to the NPDES program are required to file a renewal application to the appropriate Regional Water Board 180 days prior to the expiration of the current NPDES permit. That application must contain all relevant data and information that will support Regional Water Board's development of appropriate effluent limitations and permit conditions.

Baseline:
Information submitted in support of NPDES permit renewal applications is determined on a case-by-case basis by the appropriate Regional Water Board.

Alternatives:
1. Allow the Regional Water Board to determine baseline monitoring requirements without minimum statewide guidance.
2. Establish specific IM/E baseline monitoring and implementation plan requirements for Track 1 and Track 2 facilities.
3. Identical to Alternative 2, except that the requirements apply to Track 2 facilities only.

Discussion:
Baseline monitoring is an important aspect of the proposed Policy because it allows the Regional Water Board to establish compliance criteria that will be used to verify the performance of the technologies that are selected to meet the performance standards.

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[92] 69 FR 41685 (No. 131)
[93] EPRI. Issues Analysis of Retrofitting Once-Through Cooled Plants with Closed-Cycle Cooling. 2007.

Alternative 1 would continue the status quo permitting process as it relates to §316(b) in that specific data and study parameters are determined solely by the Regional Water Board. This alternative is similar to the case-by-case, BPJ approach that has led to inconsistent application of the BTA standard from region to region. Allowing the Regional Water Board to determine what baseline monitoring should be performed would not support the goals of a statewide policy.

Alternative 2 would require all facilities (Track 1 and Track 2) to conduct specific IM/E studies and data collection efforts that must receive the Regional Water Board's approval and be performed prior to NPDES permit reissuance. Impingement monitoring would consist of at least one year of sampling conducted at different times of the year over 24 hours so that species seasonal abundance can be accurately characterized. Likewise, entrainment monitoring would be performed for at least one year in such a way as to accurately reflect the temporal, seasonal, and diel variation in larval composition that can occur at a particular location. Taxonomic identification of all individuals collected to the lowest practicable level would also be required so that species composition may be accurately estimated in entrainment loss calculations (e.g., habitat production foregone, empirical transport model).

The baseline impingement and entrainment studies may not necessarily be limited to just twelve months. Twelve consecutive months is the minimum period recommended for monitoring. The Regional Water Board has the discretion to require further baseline impingement studies when changing operational or environmental conditions indicate that new studies are needed. Likewise, with regard to entrainment monitoring, the Regional Water Board may require additional monitoring to determine larval composition and abundance in the source water, representative of the marine life that is being entrained. The sampling must reflect reasonably expected oceanographic conditions, which may require more than one year of baseline study.

For both impingement and entrainment monitoring, a facility would be allowed to demonstrate, to the Regional Water Board's satisfaction, that it has already conducted sampling that accurately reflects current conditions. In this case, it would be the Regional Water Board's decision whether to utilize only existing study information or require additional baseline monitoring. This option recognizes that many facilities conducted considerable impingement and entrainment studies to satisfy Phase II requirements prior to that rule's suspension.

Previous entrainment studies were performed usually with a plankton net mesh size of approximately 333-335 microns. Since these studies were approved by the Regional Water Boards, staff believes these studies may be acceptable to the Regional Water Boards as baseline entrainment studies as long as they are representative in terms of oceanographic and operational conditions. A 200 micron mesh would better characterize the small invertebrate larvae that are very important ecologically but have traditionally not been sampled. Examples include both abalone and sea urchin larvae, which are not captured by a 333 micron net (See Figure 16). Furthermore, a 333 micron plankton net may not sample even all of the ichthyoplankton, since some fish may pass through a 333 micron mesh (e.g., head first or tail first). If the Regional Water Board determines that a new baseline entrainment study needs to be performed to determine larval composition and abundance in the source water, representative of water that is being entrained, then such studies should still utilize a 333 or 335 micron mesh net but should also include a sampling for the 335-200 micron size fraction.

The facility would be required to submit an implementation plan that identifies the compliance track it intends to follow, including a description of the design and construction technologies or operational measures to be used to satisfy the relevant performance standards. At that time the

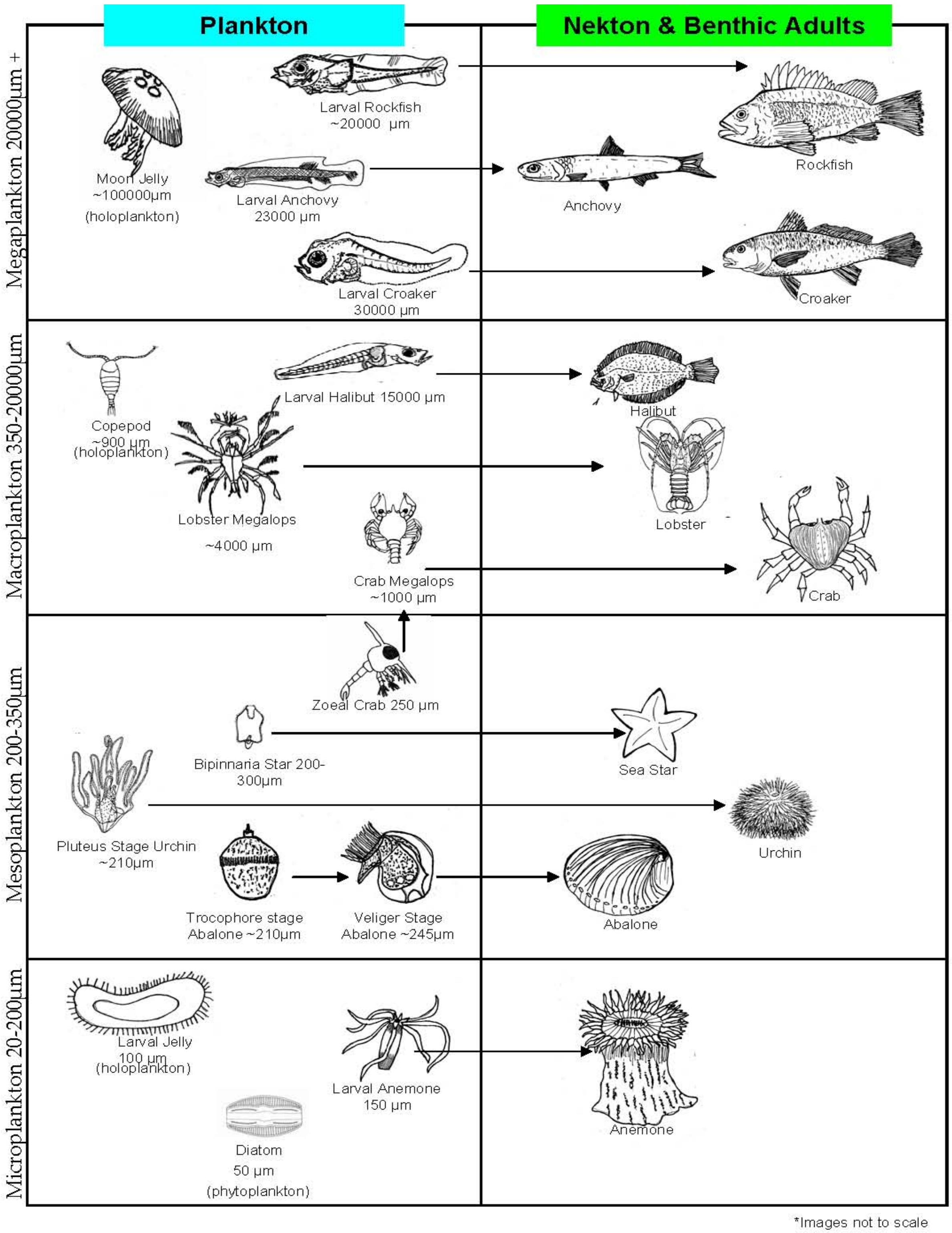

Figure 16. Planktonic Stages and Approximate Sizes of Fish Larvae (Ichthyoplankton), Invertebrate Meroplankton, Invertebrate Holoplankton and Phytoplankton.

(Ichthyoplankton and Meroplankton show arrows to indicate their adult life stages. Holoplankton and Phytoplankton are planktonic for their entire life cycle.)

facility may also submit documentation demonstrating the effectiveness of existing technologies or operating measures, in whole or in part, whose primary purpose was to control IM/E and was implemented prior to the effective date of the proposed Policy. If the Regional Water Board agrees, existing IM/E reductions may be credited towards meeting the appropriate performance standard.

Alternative 3 implements the same provisions as Alternative 2, except that it excludes Track 1 facilities and applies baseline monitoring requirements to Track 2 facilities only. A facility opting to comply using Track 1 is required to reduce its intake flow rate by 93 % and limit through screen velocity to no more than 0.5 ft/sec; explicit IM/E performance standards are not included for Track 1. State Water Board staff has concluded that intake velocity and flow rate reductions are the most direct and certain method for reducing IM/E impacts to acceptable levels based on the commonly held assumptions that entrainment is proportional to flow and impingement is primarily driven by high through-screen velocities. It is unnecessarily burdensome, therefore, to require a facility to conduct baseline monitoring when that data will not be used to determine compliance.

Staff Recommendation:
Staff recommends Alternative 3: Establish specific IM/E baseline monitoring and implementation plan requirements for Track 2 facilities.

Policy Section(s):
Appendix A, Section 4 (*Track 2 Monitoring Provisions*)

3.9 WHAT POST-IMPLEMENTATION MONITORING REQUIREMENTS SHOULD BE INCLUDED IN THE PROPOSED POLICY?

California Water Code §§13267 and 13383 authorize the State or Regional Water Board to require technical monitoring requirements and special studies for all facilities subject to California Water Code §13160. At 40 CFR §§122.41 and 122.48, USEPA requires that all NPDES permits must specify monitoring and reporting requirements to verify compliance with effluent limitations and permit conditions. Periodic monitoring allows the Water Boards to continually evaluate a facility's compliance status and provides the permitted facility with immediate feedback as to its own performance. The Water Boards maintain some discretion in establishing the specific monitoring requirements provided they could be used to verify the permitted activity.

Baseline:
Each Regional Water Board develops specific monitoring requirements for each of the permit conditions implementing §316(b). Requirements vary from Region to Region.

Alternatives:

1. Do not require any facility (Track 1 or Track 2) to conduct further monitoring after implementation; compliance is determined based on IM/E performance estimates contained in the implementation plan.

2. Require all facilities (Track 1 and Track 2) to conduct frequent IM/E monitoring consistent with uniform standards prescribing sampling methods, frequency, and compliance metrics.

3. Require all facilities (Track 1 and Track 2) to conduct periodic IM/E monitoring, but defer to the Regional Water Board to develop specific monitoring elements.

4. Allow Track 1 facilities to demonstrate compliance by verifying the proposed technology-based intake flow rate and velocity measures have been implemented and continue to function as intended. Require Track 2 facilities to conduct post-implementation IM/E monitoring according to general statewide requirements, with impingement and entrainment sampling specifics to be designed to the applicable Regional Water Board's satisfaction.

Discussion:
The proposed Policy adopts a two track approach to determining BTA at each facility in recognition that not all facilities will be able to comply with the Track 1 requirements to reduce the intake flow rate by 93% and velocity to no more than 0.5 ft/sec. Although Track 1 and Track 2 will each achieve an acceptable IM/E reduction, the means by which performance is verified is different.

Track 1 specifies a highly protective technology-based performance requirement that is certain and verifiable, and will achieve consistent performance as long as the selected measures are operated and maintained as intended. Intake flow rate and velocity restrictions will achieve substantially similar proportional IM/E reductions regardless of local conditions such as water body type and species composition. Track 2, on the other hand, allows a facility to select any combination of design and construction technologies or operational measures that will achieve IM/E reductions comparable to Track 1. The performance of many of these alternative measures varies from site to site depending on numerous factors, including the hardiness of the species that may be impacted. USEPA noted this variation in its Phase I and Phase II Technical Development Documents and discussed technology performance in terms of ranges rather than specific values.

Alternative 1 would exclude specific monitoring provisions from the proposed Policy and instead base compliance on estimated IM/E reductions the facility believes will be achieved once the selected measures have been implemented. No further monitoring would be required. For example, a facility that installs a fish barrier net to reduce impingement mortality would be able to claim a certain reduction based on applications at other locations, laboratory evaluations or a pilot study at the facility. Once an acceptable performance level is demonstrated, the facility would not be required to conduct periodic IM/E sampling to verify performance. The facility would verify compliance by demonstrating the technology was properly maintained and operating as intended.

This alternative would be insufficient to satisfy the NPDES monitoring requirements for Track 2 facilities. While the selection of alternative measures is based on reasonable performance assumptions, the IM/E reductions are by no means certain.

Alternative 2 would require all facilities, Track 1 or Track 2, to perform frequent periodic IM/E monitoring subject to specific, statewide requirements describing the sampling methods, frequency of sampling, and metrics used to evaluate compliance. For example, the proposed Policy could require all facilities to conduct monthly impingement monitoring and measure compliance based solely on the impingement rate of the most prevalent species as determined prior to implementation. Likewise, monthly entrainment monitoring could be required with compliance based on enumeration of all eggs and larvae and a specified calculation model.

In two ways, this alternative would conflict with broader NPDES goals that seek to avoid unnecessary and overly prescriptive monitoring requirements. First, IM/E monitoring may not be required to verify compliance under Track 1 since performance is based on intake flow rate and velocity reductions; it may be more appropriate to monitor other factors instead, such as monthly intake flow and head loss measurements at the screens. Second, the IM/E is a variable impact that depends on site-specific conditions including water body type, intake configuration, and species composition. It is not practical to assume the proposed Policy could adopt specific monitoring conditions that would apply to all facilities. Likewise, specific compliance metrics are more appropriately developed by the Regional Water Board to reflect site-specific permit conditions.

Alternative 3 would require all facilities (Track 1 and Track 2) to conduct periodic IM/E monitoring, and would continue the current practice of deferring to the Regional Water Board to develop specific IM/E sampling requirements to demonstrate compliance. However, this alternative would still conflict with broader NPDES goals to provide statewide consistency in monitoring programs, and would not provide guidance to Regional Water Board permit writers. In addition, IM/E monitoring for Track 1, if required by a Regional Water Board, would not be useful in verifying compliance since performance is based on intake flow rate and velocity reductions.

Alternative 4 separates monitoring requirements for Track 1 and Track 2. A facility complying under Track 1 would be exempt from further verification monitoring provided it can demonstrate, to the Regional Water Board's satisfaction, that it has implemented, for each unit, technology-based intake flow rate and velocity reduction measures that will achieve the Track 1 performance standards (a minimum of 93% intake flow rate reduction; a maximum through-screen velocity of 0.5 ft/sec). USEPA proposed a similar approach in the Phase II rule.[94]

This alternative requires a facility complying under Track 2 to conduct post-implementation IM/E monitoring, to the Regional Water Board's satisfaction, in order to demonstrate the selected technology-based controls consistently achieve the performance standard. Direct monitoring of IM/E is most critical when a facility opts to implement controls that do not have consistent performance from one facility to the next, or when multiple control measures will be used that collectively reach the performance standard.

Under Alternative 4, general statewide requirements for IM/E monitoring are provided, with specific monitoring plans to be designed to the Regional Water Board's satisfaction. For plants relying solely on reductions in velocity, post-implementation impingement monitoring would be performed by monthly verification of through-screen intake velocity at each plant intake, not to exceed 0.5 ft/sec. For other impingement controls, the owner or operator would be required to perform impingement monitoring in the same way as provided in the policy for baseline monitoring.

Post-implementation entrainment monitoring would be required, but specific requirements for entrainment sampling are not prescribed. Since Track 2 may involve a variety of different control strategies at different facilities, flexibility is necessary to design appropriate sampling approaches. For example a facility that uses wedgewire screens or a deep water intake would not be able to use the same sampling approach as baseline sampling. A facility that relies solely on intake flow controls to meet Track 1 performance standards (93% reduction) would only need to monitor monthly flow (instead of performing entrainment sampling). The approach of using flow monitoring as a substitute for entrainment monitoring in such cases was endorsed by the Expert Review Panel.

Staff Recommendation:

[94] 69 FR 41685 (No. 131).

Staff recommends Alternative 4: Allow Track 1 facilities to demonstrate compliance by verifying the proposed technology-based intake flow rate and velocity measures have been implemented and continue to function as intended. Require Track 2 facilities to conduct post-implementation IM/E monitoring according to general statewide requirements, with impingement and entrainment sampling specifics to be designed to the Regional Water Board's satisfaction. Track 2 facilities relying only on velocity controls would not need to perform impingement sampling, but instead would verify through-screen intake velocity. Track 2 facilities relying only on flow controls would not need to perform entrainment sampling, but instead would need to monitor monthly flow.

Policy Section(s):
Appendix A, Section 4 (*Track 2 Monitoring Provisions*).

3.10 SHOULD A MAKEUP WATER SOURCE BE SPECIFIED FOR TRACK 1?

Closed-cycle wet cooling systems reject heat to the surrounding environment by evaporating a small portion of the recirculating water flow. This evaporative loss, approximately 1-2% of the circulating flow, gradually increases the water's dissolved solids concentration and requires a continuous flushing (blowdown) to maintain desirable water quality. Makeup water must be obtained to compensate for evaporation and blowdown (as well as minor drift losses), the volume of which is dependent on the source water's initial dissolved solids content and the cycles of concentration used in the system's design. Salt water cooling towers, the default design used for all of the State's OTC facilities in the Tetra Tech report, typically operate at 1.5 cycles of concentration unless site-specific limits require a lower value. At this level, salt water towers will require makeup water at a rate that is approximately 94% less than the OTC system.

When retrofitting to closed-cycle wet cooling, it is not necessary to continue using the OTC source water as the makeup water source. Alternative water sources, in fact, can provide additional benefits that may make its use preferable over marine or estuarine waters. Furthermore, the State Water Board's 1975 *Quality Control Policy on the Use and Disposal of Inland Waters Used for Power Plant Cooling* required new power plants to consider using reclaimed water instead of freshwater.[95] There is no similar policy regarding the use of marine waters, although Porter-Cologne encourages the use of recycled water in the coastal zone as a supplement to surface and ground water sources, and may be made available for industrial uses provided it meets certain discharge criteria.[96]

Reclaimed water combined with a closed-cycle cooling system could eliminate a facility's surface water withdrawals, thereby eliminating IM/E as well. Because reclaimed water typically has a much lower dissolved solids concentration than marine water, a smaller, less costly tower may be possible. The overall cost savings may be negligible, however, if the cost to procure, treat, and transport the reclaimed water is substantial. For many of the State's OTC facilities, reclaimed water would require extensive new infrastructure (underground or offshore piping, pumps) that would be installed in urbanized areas. The Tetra Tech report evaluated potential reclaimed water sources for 13 OTC facilities (see Table 14, below).

Table 14. Reclaimed Water Sources

[95] State Water Resources Control Board, Resolution 75-58. 1975.
[96] CWC §13142.5(e)(1) and (2)

Facility	Design Intake Capacity (MGD)	Wet Cooling Tower Makeup Demand (MGD)	Percent Reduction (%)	15 Mile Reclaimed Water Sources and Capacity
Alamitos	1152	57	95	LA Sanitation (Carson)—330 MGD Los Coyotes (Cerritos)—33 MGD Terminal Island (San Pedro)—20 MGD OC Sanitation (Huntington Beach)—232 MGD Long Beach (Long Beach)—20 MGD
Huntington	484	26	95	OC Sanitation (Huntington Beach)—232 MGD Long Beach (Long Beach)—20 MGD
Haynes	858	36	95	LA Sanitation (Carson)—330 MGD Los Coyotes (Cerritos)—33 MGD Terminal Island (San Pedro)—20 MGD OC Sanitation (Huntington Beach)—232 MGD Long Beach (Long Beach)—20 MGD
Harbor	81	4.6	94	LA Sanitation (Carson)—330 MGD Los Coyotes (Cerritos)—33 MGD Terminal Island (San Pedro)—20 MGD Long Beach (Long Beach)—20 MGD
El Segundo	379	20	95	LA Sanitation (Hyperion)—350 MGD LA Sanitation (Carson)—330 MGD
Diablo Canyon	2484	108	96	None
Contra Costa	431	20	95	Delta Diablo (Antioch)—14 MGD Trilogy (Rio Vista)—0.5 MGD Brentwood (Brentwood)—5 MGD
Moss Landing	1166	56	95	Watsonville (Watsonville)—10 MGD Monterey Regional (Marina)—30 MGD
Mandalay	241	13	95	Ventura (Ventura)—14 MGD Oxnard (Oxnard)—31 MGD
Pittsburg	462	20	96	Benicia (Benicia)—3 MGD Central Contra Costa (Concord)—45 MGD Delta Diablo (Antioch)—14 MGD
Ormond Beach	654	47	93	Ventura (Ventura)—14 MGD Oxnard (Oxnard)—31 MGD
SONGS	2287	110	95	Oceanside Outfall (Oceanside)—27 MGD SOCWA (San Juan Creek)—19 MGD San Clemente (San Clemente)—5 MGD
Scattergood	495	23	95	LA Sanitation (Hyperion)—350 MGD LA Sanitation (Carson)—330 MGD

Baseline:
The 1975 policy requires facilities that would otherwise withdraw from freshwater sources to consider reclaimed water instead.

Alternatives:

1. Do not specify source water preferences for makeup water.

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

Discussion:
Alternative 1 is inconsistent with the State Water Board's 1975 policy direction regarding the use of recycled wastewater. Furthermore, 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 recently adopted a recycled water policy.[97]

Alternative 2 is consistent with the State Water Board's new recycled water policy. Alternative 2 is also consistent with the 1975 policy and expands the scope to marine and estuarine waters as well. Reclaimed water cannot be used as a direct replacement for OTC water demand (with fewexceptions), although it may be used to *supplement* OTC flows and achieve a partial flow reduction. A wet cooling tower's reduced water demand makes reclaimed water more suitable for use as makeup source provided the water is available and treated to meet standards contained in Title 22 of the California Code of Regulations. In some cases this may be a feasible and desirable alternative, such as at Huntington Beach where a significant volume of water is available nearby, or at Mandalay, where reclaimed water might enable to the facility to avoid ongoing permit compliance issues related to the presence of copper in the intake water. State Water Board staff recognizes that increasing demands for reclaimed water in other uses (e.g., irrigation, ground water injection, salt water intrusion barriers), particularly in southern California, may complicate availability.

Staff Recommendation:
Staff recommends Alternative 2: Require that power plant owners consider the feasibility of using recycled wastewater for power plant cooling, either to supplement OTC or as makeup water in a closed-cycle system, when developing their implementation plans.

Policy Section(s):
Appendix A, Section 1 (*Introduction*)
Appendix A, Section 3.A(2) (*Implementation Provisions*)

3.11 SHOULD THE PROPOSED POLICY INCLUDE A STATEWIDE COMPLIANCE SCHEDULE?

This proposed Policy establishes intake flow rate and velocity reductions as BTA. Within the narrow scope of the proposed Policy, compliance will involve retrofitting the existing OTC system to closed-cycle wet cooling (Track 1) or adopting other measures that achieve the IM/E performance standards (Track 2) in a prescribed timeframe. The age and relative inefficiency of many OTC units, however, increase the likelihood that facilities will opt to comply with the proposed Policy by retiring one or more units or replacing them with new, more efficient generation technologies that use dry or alternative cooling systems. Unlike other industrial sectors or point source discharge categories, power plants do not operate wholly independent from one another in that they supply a common electrical transmission grid and can be called upon to balance the electrical load as units from other power plants are taken offline. State Water Board staff recognized this possibility by convening the IAWG to address the interconnected issues that might be raised in the event multiple units are retired or repowered.

[97] State Water Board Resolution No. 2009-0011 (Adoption of a Policy for Water Quality Control for Recycled Water), effective May 14, 2009

Alternatives:

1. Require all facilities to comply with the proposed Policy within the minimum timeframe needed to retrofit to closed-cycle wet cooling.
2. Delegate compliance scheduling to the appropriate Regional Water Boards.
3. Establish facility-specific compliance dates based on known replacement and upgrade projects and collaboration with other State agencies. Address unforeseen changes to facility status by establishing a process to periodically re-assess compliance dates and amending the Policy as needed.

Discussion:
A fossil-fueled facility that opts to comply by installing closed-cycle wet cooling will be required to obtain the necessary permits prior to initiating construction, a process that can take up to one year or more. The construction phase may last six months or more depending on the size and complexity of the retrofit, while final connections to integrate the new system with the existing facility can last up to four weeks. Timelines for nuclear-fueled facilities can be significantly longer to address their more stringent regulatory and safety requirements.

Alternative 1 would assume that all facilities (except Diablo Canyon and SONGS) would have compliance deadlines extending two to three years beyond the effective date of the proposed Policy. No coordinated effort would be made to balance electrical demand or transmission grid reliability. According to the grid reliability study prepared by Jones and Stokes, Alternative 1, if implemented, could trigger the retirement of more than 15,000 MW of capacity without consideration for replacement power sources, which would have to be supplied by less efficient generating technologies and cause significant secondary environmental impacts at a cost of more than $11 billion.[98]

Alternative 2 would establish a statewide BTA determination but leave decisions regarding implementation to the Regional Water Boards. This alternative would run counter to the State Water Board staff's stated goals of coordinating implementation at the state level to reduce the burden on Regional Water Boards and address issues that extend beyond an individual board's jurisdiction.

Alternative 3 recognizes the likelihood that many fossil-fueled units will achieve compliance through retirement, re-powering, or infrastructure upgrades. 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. To that end, State Water Board staff convened the IAWG to solicit input from California's energy and permitting agencies. The implementation schedule in the proposed Policy was developed with input from the IAWG. As part of that process, the energy agencies (CEC, CPUC, and CAISO) proposed their recommended implementation schedule (see Appendix C). The proposed Policy contains a

Table 15. Implementation Schedule

[98] Jones and Stokes, OTC Reliability Study, 2008.

Facility	Compliance Date [time after the effective date of the Policy]	Basis
Humboldt Bay Power Plant	[1 year]	Repowering project approved by CPUC and expected to operational by the end of 2010.
Potrero Power Plant	[1 year]	Completion of infrastructure replacement project expected by end of 2010.
South Bay Power Plant	12/31/2012	Expected closed by 2012.
El Segundo Generation Station	12/31/2015	Repowering proposed.
Harbor Generating Station	12/31/2015	Proposal submitted by LADWP.
Morro Bay Power Plant	12/31/2015	Contract with SCE expires in 2011. CAISO report indicates not needed for resource adequacy.
Encina Power Plant	12/31/2017	CPUC 2010 Long Term Procurement Plan.
Contra Costa Power Plant	12/31/2017	CPUC 2010 Long Term Procurement Plan.
Pittsburg Power Plant	12/31/2017	CPUC 2010 Long Term Procurement Plan.
Moss Landing Power Plant	12/31/2017	CPUC 2010 Long Term Procurement Plan.
Haynes Generating Station	12/31/2019	Proposal submitted by LADWP.
Scattergood Generating Station	12/31/2020	Proposal submitted by LADWP.
Huntington Beach Generating Station	12/31/2020	CPUC 2012 Long Term Procurement Plan.
Redondo Beach Generating Station	12/31/2020	CPUC 2012 Long Term Procurement Plan.
Alamitos Generating Station	12/31/2020	CPUC 2012 Long Term Procurement Plan.
Mandalay Generating Station	12/31/2020	CPUC 2012 Long Term Procurement Plan.
Ormond Beach Generating Station	12/31/2020	CPUC 2012 Long Term Procurement Plan.
SONGS	12/31/2022	Concurrent with NRC operating license renewal.
Diablo Canyon Power Plant	12/31/2024	Concurrent with NRC operating license renewal.

provision to continue this collaborative approach by establishing a Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) that will include agencies with oversight in energy resource planning and permitting. The SACCWIS will assist in reviewing scheduled conversions to BTA by existing power plants. The SACCWIS will report to the State Water Board annually with recommendations on modifications to the implementation schedule, and the State Water Board will consider the SACCWIS' recommendations and direct staff to make modifications, if appropriate, for the State Water Board's consideration. Table 15 above, presents the proposed Policy's proposed implementation schedule and basis.

Staff Recommendation:
Staff recommends Alternative 3: Establish facility-specific compliance dates based on known replacement and upgrade projects and collaboration with other State agencies. Address unforeseen changes to facility status by establishing a process to periodically re-assess compliance dates and amending the Policy as needed.

Policy Section(s):
Appendix A, Section 1 (*Introduction*)
Appendix A, Section 3.B (*Implementation Provisions-SACCWIS*)
Appendix A, Section 3.E (*Implementation Provisions-Implementation Schedule*)

3.12 SHOULD THE PROPOSED POLICY INCLUDE INTERIM REQUIREMENTS?

Implementation of the proposed Policy is likely to occur over several years, with a significant time lapse between adoption and final compliance for several facilities. According to the proposed implementation schedule, Diablo Canyon and SONGS will not be required to comply for more than ten years beyond the proposed Policy's effective date with several other facilities required to be in compliance by 2020. Impacts to marine life will continue during this interim period.

Baseline:
Not applicable.

Alternatives:

1. Exclude all interim requirements.
2. Establish interim IM/E requirements using technology-based methods only. Require all facilities with offshore intakes to install large organism (e.g., marine wildlife) exclusion devices and require additional restrictions on intake flows not directly associated with power generating activities.
3. Establish interim IM/E requirements with mitigation as a compliance method. Mitigation would be defined as projects to restore marine life lost through impingement mortality and entrainment; restoration of marine life may include projects to restore and/or enhance coastal marine or estuarine habitat, and may also include protection of marine life in existing marine habitat.
4. Establish interim IM/E requirements using technology-based methods (as in Alternative 2) and require interim mitigation (as in Alternative 3)

Discussion:

Large Organism Entrapment

The federal Marine Mammal Protection Act[99] was established in 1972 to protect important marine species and established a moratorium on “taking”[100] marine mammals, except under narrowly drawn circumstances as authorized by an appropriate permit. All sea turtles, including Green and Loggerhead turtles, are currently listed as threatened under the federal Endangered Species Act[101]. More broadly, the California Ocean Protection Act[102] provides a set of guiding principles for all state agencies to follow in protecting the State's coastal and ocean resources, with an emphasis on interagency coordination to implement state policies such as the Marine Life Protection Act[103].

The National Marine Fisheries Service has reported to State Water Board staff that large organisms such as marine mammals and sea turtles are regularly entrapped in offshore intakes, often resulting in mortality. Table 16 and Table 17, below, show that large organism entrapment for coastal OTC facilities is a significant issue for coastal OTC facilities, particularly those facilities with offshore intakes.[104]

The proposed Policy’s principal goal is to minimize the impacts to the State’s coastal aquatic communities that can occur with uncontrolled OTC operation; large marine organisms are a critical component to overall health and stability of these communities. Because the proposed Policy addresses the unique characteristics associated with power plants, it is appropriate to include measures to control these “takings” independent from other state agency initiatives that address impacts associated with commercial fishing and other activities. At cooling water intake

Table 16. Marine Mammal Entrapment

		California Sea Lion			Harbor Seal		
Facility	**Years**	**Alive**	**Dead**	**Total**	**Alive**	**Dead**	**Total**
Diablo Canyon	1982-2006	0	2	2	0	0	0
El Segundo*	1982-2006	2	5	7	2	1	3
Encina	1982-2006	1	4	5	0	1	1
Huntington Beach*	1991-2006	1	1	2	0	0	0
Mandalay	1982-2006	2	4	6	0	0	0
Morro Bay	1982-2006	0	0	0	0	0	0
Moss Landing	1982-2006	2	2	4	0	2	2
Ormond Beach*	1991-2006	3	20	23	11	5	16
Redondo Beach*	1991-2006	1	4	5	6	8	14
Scattergood*	1991-2006	13	47	60	1	3	4
SONGS*	1991-2006	90	227	317	148	93	241
South Bay	1982-2006	0	0	0	0	0	0
Total		**115**	**316**	**431**	**168**	**113**	**281**

Note: *Facility operates an offshore intake structure.

[99] See, 50 CFR Part 216.
[100] “Taking” is defined as any attempt “to hunt harass, capture, or kill” marine mammals.
[101] Current listings available at http://www.fws.gov/endangered/ .
[102] CA Public Resource Code §§ 35500-35650.
[103] CA Fish and Game Code §§ 2850-2863.
[104] Data provided by Dan Lawson, NMFS/NOAA in 2009 via personal communication.

Table 17. Sea Turtle Entrapment

		Green Turtle			Loggerhead Turtle		
Facility	**Years**	**Alive**	**Dead**	**Total**	**Alive**	**Dead**	**Total**
Diablo Canyon	1983-2005	7	0	7	0	0	0
El Segundo*	1982-2006	1	1	2	1	0	1
Encina	1982-2006	2	1	3	0	0	0
Huntington Beach*	1982-2006	0	0	0	0	0	0
Ormond Beach*	1982-2006	1	0	1	0	0	0
Redondo Beach*	1982-2006	2	1	3	0	0	0
Scattergood*	1982-2006	3	0	3	3	0	3
SONGS*	1983-2005	29	2	31	2	0	2
Total		**45**	**5**	**50**	**6**	**0**	**6**

Note: *Facility operates an offshore intake structure

structures, these impacts are primarily addressed by installing screening devices that prevent access to the main cooling system and would not necessarily be mitigated by reducing the intake flow. Furthermore, large organism entrapment will continue until a facility has reached full compliance with the BTA standards and should be addressed in a timelier manner than the proposed IM/E implementation schedule.

Large organism entrapment can be readily controlled by installing exclusion devices on an offshore intake structure that reduce the linear distance between bars to no more than 9 inches in any direction. At the Scattergood facility, for example, the offshore intake extends approximately 1,500 feet offshore into Santa Monica Bay and is fitted with a velocity cap to control impingement. The velocity cap was not originally designed with smaller openings to prevent large animals from entering the intake conduit and becoming trapped in the forebay or against the traveling screens. LADWP modified the velocity cap design in 2008 by installing exclusion bars that reduced the maximum contiguous open space to no more than 9 inches square. Post-installation data were not available for this document, but LADWP reports that the modifications have proven to be effective in reducing the numbers of large marine animals drawn into the cooling system.[105]

Incidental Cooling Water Withdrawals

In some cases, OTC facilities continue to withdraw water at times that are not directly related to power generating activities. This might be done to prevent condenser biofouling, comply with NPDES permit requirements, or to provide a secondary benefit by inducing turnover in the source water body to prevent stagnation. At Redondo Beach, for example, the current NDPES permit requires the facility to conduct weekly pH and quarterly chronic toxicity monitoring even during inactive times. Pumps must be run in order to comply with the permit conditions.[106] At El Segundo, for example, it had been the standard procedure to operate one intake pump for Units 1 and 2 in order to provide the necessary dilution for the small sewage treatment plant located onsite.[107] This activity is no longer necessary, however, following the commencement of the Unit 1 and 2 replacement project. It is not clear how common such practices are among the State's OTC facilities, but they have been identified at several locations.

[105] H. David Nahai. LADWP. Comment Letter on March 2008 Scoping Document. May 20, 2008.
[106] Clement Thompson. AES Redondo Beach. Renewal of Waste Discharge Requirements/NPDES Permit for Redondo Beach Generating Station. November 12, 2004.
[107] Los Angeles Regional Water Board Order No. 00-084.

The proposed implementation schedule would allow this secondary IM/E impact to continue unabated for up to ten years unless interim measures are included in the proposed Policy. In the 2008 Scoping Document, State Water Board staff had initially proposed an interim requirement that would have limited intake flows to no more than 10% of the average daily flow when electricity is not being produced for a period of two or more consecutive days. Additional analysis shows that this provision would be confusing and difficult to implement as an interim requirement. Instead the proposed Policy includes a provision directing all OTC facilities to cease intake flows that are not directly related to power generating activities within one year, unless the facility demonstrates that such flows are necessary for safe operation.

Restoration

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 IM/E losses. At Moss Landing, for example, the facility's existing NPDES permit found that the §316(b) BTA standard was met, in part, by funding the Elkhorn Slough Enhancement Program (ESEP) to "mitigate significant effects of larvae entrainment" from the cooling water intake structure.[108] SONGS currently participates in restoration and mitigation projects to comply with its coastal development permit (CDP) issued by the California Coastal Commission in 1974.[109] These efforts have included restoring the San Dieguito River mouth and coastal lagoon, constructing a kelp reef and support for a California sea bass hatchery.[110]

The Phase I rule, as initially adopted, allowed new facilities to comply with that rule's Track 2 by using restoration measures to compensate for IM/E impacts. 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 . . ."[111] USEPA included restoration in the Phase II rule as well, claiming the circumstances for existing facilities were manifestly different from new facilities and required a broader scope of available compliance measures. In *Riverkeeper II*, the Second Circuit Court of Appeals reached the same conclusion for existing power plants, concluding that restoration measures, such as restoring habitat or restocking fish, conflict with the statute and cannot be considered BTA.

While restoration cannot be used to comply with the BTA standard, State Water Board staff recognizes restoration is a valuable tool that can be used to offset IM/E impacts during the interim period between the proposed Policy's adoption and full compliance. Interim measures are appropriate when the compliance period is lengthy for some facilities (up to ten years for fossil fueled units) and IM/E impacts are expected to continue unabated.

Existing IM/E controls and Mitigation Efforts at the OTC Facilities

Table 18, below, shows existing IM/E controls at the various OTC facilities. SONGS has participated in several restoration and mitigation programs under its coastal development permit (CDP) issued by the CCC (No. 183-73, dated 2/28/1974). Agreements reached under the CDP

Table 18. Existing IM/E Controls at the OTC Facilities

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[108] Central Coast Regional Water Board Order No. 00-041, Findings 50 and 51.
[109] CCC Permit No. 183-73. February 28, 1974.
[110] Thomas Gross. SCE. Comment Letter on March 2008 Scoping Document. May 20, 2008.
[111] 358 F.3d at 190.

Region	Facility/Intake Structures [a]	Intake Water Body Type	Intake Location	Screens/Fish Protection Devices*	Opening Size at Intake Entrance
1	Humboldt Bay	estuary/bay	shoreline (surface)	BR-TS	?
2	Pittsburg	estuary/tidal river	shoreline (surface)	BR-TS-VFD	bar racks 3.5" spacing
2	Potrero	estuary/bay	shoreline (surface)	BR-TS	bar racks 3.5" spacing
3	Diablo Canyon	ocean	shoreline (surface)	BR-TS	bar racks 3" on center
3	Morro Bay	estuary/bay	shoreline (surface)	BR-TS	bar racks 4" on center
3	Moss Landing Units1 and 2	enclosed bay/harbor	shoreline (surface)	BR-ITS	bar racks 3.5" spacing
3	Moss Landing Units 6 and 7	enclosed bay/harbor	shoreline (surface)	BR-TS	bar racks 3" on center
4	Alamitos Units 1-4	enclosed bay/harbor	shoreline (surface)	BR-TS [b]	bar racks 3" spacing
4	Alamitos Units 5and 6	enclosed bay/harbor	shoreline (surface)	BR-TS	bar racks 3" spacing
4	El Segundo Units1 and 2	ocean	offshore (2,000')	VC-BR-TS	2' x ? at VC
4	El Segundo Units 3 and 4	ocean	offshore (2,000')	VC-BR-TS	3' x ? at VC
4	Harbor	enclosed bay/harbor	shoreline (surface)	BR-TS	bar racks 4.5" on center
4	Haynes	enclosed bay/harbor	shoreline (surface)	BR-TS-SS	bar racks 6" on center
4	Mandalay	enclosed bay/harbor	shoreline (surface)	BR-SS	bar racks 2.5" spacing
4	Ormond Beach	ocean	offshore (1790')	VC-BR-TS	4' x 14" at VC
4	Redondo Beach Units 5 and 6	enclosed bay/harbor	offshore (250')	VC-BR-TS	4' x 18" at VC
4	Redondo Beach Units 7 and 8	ocean	offshore (1000')	VC-BR-TS	4' x 18" at VC
4	Scattergood	ocean	offshore (1600')	VC-BR-TS	5' x 9" at VC
5	Contra Costa	estuary/tidal river	shoreline (surface)	BR-TS-VFD	bar racks 3.5" spacing
8	Huntington Beach	ocean	offshore (1200')	VC-BR-TS	5' x 18" at VC
9	Encina	enclosed bay/harbor	shoreline (surface)	BR-TS	bar racks 3.5" on center
9	SONGS Unit 2	ocean	offshore (3183')	VC-BR-ATS-GV-FR	7' at VC (no intermittent bars)
9	SONGS Unit 3	ocean	offshore (3183')	VC-BR-ATS-GV-FR	7' at VC (no intermittent bars)
9	South Bay	enclosed bay/harbor	shoreline (surface)	BR-TS	bar racks 3" spacing

Notes:
*BR = bar racks; TS = traveling screens; SS = slide screens; ITS = inclined traveling screens; ATS = angled traveling screens;VC = velocity cap;
VFD = variable frequency drive; GV = guiding vanes; FR = fish return.
a. An intake structure is defined as “the total physical structure and any associated constructed waterways used to withdraw cooling water from waters of the U.S. The cooling water intake structure extends from the point at which water is withdrawn from the surface water source up to, and including, the intake pumps” (40 CFR 125.93). In this manner, multiple units may share a single intake structure.
b. The screenhouses for Units 3&4 do not have bar racks.

require SONGS to restore 160 acres of wetlands and 280 additional acres to be used as open space at the San Dieguito River Park in northern San Diego County (costing $86 million). SONGS is also constructing a 150-acre kelp reef off of San Clemente Beach to mitigate impacts to kelp beds from the thermal discharge costing $16 million for construction and up to $10 million for monitoring) and also funds a white sea bass hatchery to produce more than 350,000 viable young each year.

The Moss Landing facility, as directed by its current NPDES Permit (Order No. 00-041), funded $425,000 to the Monterey Bay Sanctuary Foundation for a coastal waters evaluation programdeveloped by the foundation. Moss Landing also funds (at a cost of $7 million) an aquatic habitat acquisition and enhancement project (Elkhorn Slough Enhancement Project) administered by the Elkhorn Slough Foundation with oversight by the Regional Water Board. The project seeks to mitigate the significant effects of larvae entrainment by the cooling water intake system by preserving and restoring wetlands and upland areas within the Elkhorn Slough watershed.

The Huntington Beach facility was licensed to retool its generating units in 2001 under an emergency proceeding authorized by the CEC during the energy crisis. The facility was required to conduct post-licensing studies to determine the effect of continued OTC operation on the aquatic community and any mitigation measures that might be necessary. The CEC required the Huntington Beach facility to purchase, preserve, or otherwise restore 66.8 acres of nearby wetlands to offset impacts to marine organisms. A one-time payment of $5,511,000 would be made to the Huntington Beach Wetlands Conservancy, which would administer the project.

Discussion of Alternatives

Alternative 1 would exempt all OTC facilities from any interim compliance measures. Compliance with the proposed Policy would be based solely on meeting the BTA performance standards according to the proposed implementation schedule. As noted throughout this report, State Water Board staff considers IM/E impacts from OTC operation to be a substantial stressor to the State's coastal ecosystems and requires an aggressive approach to limit further damage. Allowing IM/E impacts to continue for several years beyond the proposed Policy's effective date runs counter to the goals stated in Section 1 of this document.

Alternative 2 would require all facilities to implement only those interim IM/E controls that are considered "technology-based" under §316(b). It would address large organism impingement by requiring facilities with offshore intakes to install appropriate exclusion devices. The recent enhancements made to the Scattergood offshore intake show that restricting open areas to no more than 9 inches is an available and effective method to reduce this impact.

It would also require all facilities to cease unnecessary intake flows no later than one year following the proposed Policy's effective date. Previous discussions of this requirement referred to terms such as "generational flow" but did not further explain the various operating conditions that might be included in that category. Explicitly limiting pump operation to times when a facility is generating electricity for sale disregards necessary start-up and shut-down procedures that require cooling water and may not account for periods when boiler units are kept in a near-ready state (hot standby) so that they may quickly begin generating electricity instead of from a cold start. Furthermore, the proposed Policy must be explicit on this point with regard to additional NRC safety requirements for Diablo Canyon and SONGS. Therefore the Policy would define *power-generating activities* as directly related to the generation of electrical energy, including start-up and shut-down procedures, contractual obligations (hot stand-by), hot bypasses, and critical maintenance activities regulated by the NRC. Activities that are not considered directly related to the generation of electricity include (but are not limited to) dilution for in-plant wastes, maintenance of source and receiving water quality strictly for monitoring purposes, and running pumps strictly to prevent fouling of condensers and other power plant equipment.

Few technologies are available that would be practical and cost-effective on an interim basis, particularly those designed to reduce entrainment (e.g. fine mesh screens). Therefore limiting interim technology based controls to exclusion devices and flow controls is a more cost effective and practical approach. Alternative 3 would specifically require a mitigation project for interim compliance. The costs associated with most technology-based IM/E reduction measures preclude their use on an interim basis. Restoration, however, is a cost-effective method that can be implemented in a reasonable timeframe without placing an undue burden on the facility. Likewise, it would be overly burdensome to require interim measures for facilities that are expected to comply within a short time following the proposed Policy's effective date. This alternative, therefore, would require a facility to implement interim IM/E measures no later than five years after the proposed Policy's effective date and continuing until final compliance is attained, essentially exempting those facilities that are expected to be in compliance in the near term.

Mitigation projects are inherently site-specific and must be developed in coordination with experts familiar with the local aquatic ecosystem. Because the types of restoration programs are varied and performance is not always immediately evident, Alternative 3 allows a facility three options to satisfy the interim requirement through restoration.

- Option 1 permits the owner or operator to demonstrate appropriate compensation through existing mitigation efforts that are in development or already implemented to satisfy other environmental programs or permits, subject to the approval of the Regional Water Board. The Moss Landing, Huntington and SONGS examples cited above could be considered under this option.
- Option 2 would permit the owner or operator to provide funding to the California Coastal Conservancy which would work with the California Ocean Protection Council to fund an appropriate mitigation project. The draft version of this policy (July 2009) and its associated Appendix A draft policy originally stated this option as "demonstrating to the Regional Water Board's satisfaction that the interim impacts are compensated for by the owner or operator's participation in funding an appropriate mitigation project." However, after consideration of public comments State Water Board staff now recommends providing funding, through the Ocean Protection Council, for example to be directed toward the implementation, monitoring, maintenance and management of the State's Marine Protected Areas.
- Option 3 permits the facility to develop and implement its own mitigation program. This option would likely be the most time and cost-intensive option since it would require the facility to conduct all of the necessary activities independently, including plan development and approval.

The 2008 Scoping Document discussed the Habitat Production Foregone (HPF) method as one approach that can be used to assess entrainment losses and develop an estimated value for the restoration or mitigation project. This methodology estimates the amount of habitat it would take to produce the organisms lost to entrainment and assigns a monetary value based on the cost per acre. Estimates of lost production can be for affected individuals only or the affected individuals plus the production of progeny that were not produced. HPF is applicable to species where the habitat associated with adult production can be identified. This method can address losses across most habitat types.

HPF (a.k.a., area production foregone) method requires an estimate of the proportional mortality, i.e., the proportion of larvae killed from entrainment to the larvae in the source population as determined by an Empirical Transport Model (ETM). The product of the average proportional mortality and the source water body area is an estimate of the HPF area that is lost to all entrained species. A 2007 CEC study[112] performed by the J. Steinbeck, J. Hedgepeth, P. Raimondi, G. Cailliet, and D. Mayer in 2007 (see http://www.waterboards.ca.gov/water_issues/programs/npdes/docs/cwa316b/symposium_2007jan/john_steinbeck.pdf) supports the use of ETM coupled with "Area Production Foregone" for determining the area of adult habitat in extrapolated source water. Staff recommends the HPF method for determine the habitat and area for funding a mitigation project.

The 2007 CEC study does caution that HPF may not be applicable to all habitats and species, such as the case with open water pelagic habitat. In recognition of the limitations of HPF in certain cases, a comparable alternative method may be more appropriate. The State Water Board staff also recognizes that other methods may be more applicable on a site-specific basis, and therefore also recommends the optional use of a comparable alternate method when needed, to be approved by the State Water Board Division of Water Quality, to determine the habitat and area for funding a mitigation project.

Alternative 4 represents a combination of the approaches in Alternative 2 and Alternative 3. It would establish interim IM/E requirements using both technology-based methods and interim mitigation projects. This is a phased approach, in that exclusion devices and flow controls would be required within one year of the effective date of the policy, but mitigation projects would be required five years after the effective date. From the discussion of Alternatives 2 and 3 above this is a cost-effective and reasonable approach, immediately reducing some of the most serious impacts (wildlife entrapment, and entrainment not directly related to power generating activities) and offsetting IM/E through mitigation projects when implementation of final compliance takes greater than five years.

Staff Recommendation:
Alternative 4. Establish interim IM/E requirements, using both technology-based methods and interim mitigation projects.

Policy Section(s):
Appendix A, Section 3.C *(Implementation Provisions-Immediate and Interim Requirements*)
Appendix A, Section 5 (*Definition of Terms*)

3.13 SHOULD THE PROPOSED POLICY INCLUDE A WHOLLY DISPROPORTIONATE COST-BENEFIT TEST?

The cost-benefit method for environmental policy development is an approach that seeks to determine a proposed action's net benefit and overall cost by assigning monetary values to each category and comparing the results against an objective standard (e.g., wholly disproportionate). USEPA has used the cost-benefit approach in many different resource areas, including previous §316(b) regulatory efforts. At the State level, the §316(b) BTA standard has been evaluated using the cost-benefit approach (e.g., Moss Landing), although it is not a common practice.

[112] CEC, J. Steinbeck, J. Hedgepeth, P. Raimondi, G. Cailliet, and D. Mayer. 2007 for the CA Energy Commission, Assessing power plant cooling water intake system entrainment impacts. Report CEC-700-2007-010. 2007

Baseline:
There are no statewide policies or plans that include a cost-benefit test for power plants. Case-by-case BPJ permits have been issued for some of the State's OTC facilities (e.g., Moss Landing). The California Water Code does not require a cost-benefit test for the development of water quality control plans or policies.

Alternatives:

1. Exclude alternative requirements based on a wholly disproportionate cost-benefit test for all facilities.
2. Permit alternative requirements based on a wholly disproportionate cost-benefit test for all facilities.
3. Permit alternative requirements based on a wholly disproportionate cost-benefit test for facilities that meet minimum efficiency thresholds.
4. Permit alternative requirements based on a wholly disproportionate cost-benefit test for nuclear-fueled facilities.
5. Exclude alternative requirements based on a wholly disproportionate cost-benefit test, but provide alternative requirements for combined-cycle units and nuclear plants.

Discussion:
The "wholly disproportionate" cost test determines whether the total compliance costs are wholly out of proportion to the total benefits and has been used in §316(b) permitting procedures since the USEPA issued a formal Decision of the Administrator relating to the Seabrook Station case in New Hampshire.[113] In that decision, USEPA determined that cost may be considered as a BTA component and further found that it would be unreasonable to interpret §316(b) as requiring use of a technology "whose cost is wholly disproportionate to the environmental benefit to be gained."[114] A later ruling by the First Circuit Court of Appeals upheld this approach.[115] In the CWA, cost-benefit is explicitly authorized in several sections, although it is notably absent from §316(b). USEPA has interpreted the absence of cost-benefit provision in §316(b), either for or against, to mean that it *may* include a cost-benefit analysis as a reasonable means by which it can determine BTA. Under Phase I, USEPA did not include a wholly disproportionate cost-benefit analysis, instead relying on an economic impact and achievability analysis to determine BTA (aka "reasonably borne).[116] The Phase I preamble notes:

> EPA recognizes that it selected best technology available for minimizing adverse environmental impact on the basis of what it determined to be an economically practicable cost for the industry as a whole. USEPA did this by considering the cost of the rule as compared with the revenue of a facility, as well as the cost compared to the overall construction costs for a new facility. This approach is analogous to the economic achievability analyses it conducts for other technology-based rules under §§301 and 306 of the CWA which use very similar language to §316(b) and to which §316(b) refers, and is consistent with the legislative history of §316(b) of the CWA.[117]

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[113] Public Service Company of New Hampshire, et al. Seabrook Station, Units 1 and 2, (June 10, 1977 Decision of the Administrator) Case No. 76-7, 1977 WL 22370 (USEPA).
[114] *Id.*
[115] Seacoast Anti-Pollution League v. Costle (1st Cir. 1979) 597 F.2d 306.
[116] A cost-benefit analysis was prepared for Phase I as required by the Unfunded Mandates Reform Act (UMRA), but it was not used to determine the appropriate performance standards.
[117] 66 FR 65309 (No. 243)

For Phase II, however, USEPA prepared a cost-benefit analysis to determine BTA performance standards for the national rule and authorized a site-specific BTA assessment where a facility's compliance costs were "significantly greater" than the expected benefits. The analysis extrapolated case study benefits from 19 facilities (including the San Joaquin/Sacrament Delta) to develop a national estimate. Notably, the Phase II cost-benefit analysis was limited to direct use benefits, i.e., commercially and recreationally important species for which reasonable market data was available. Because the analyzed species typically comprise less than 2% of the impinged and entrained organisms, the Phase II cost-benefit did not monetize more than 98% of the impacted fish and shellfish. The end result was an estimated national rule benefit of $87 million (approximately $3.7 million combined for all California facilities).[118]

The US Supreme Court upheld USEPA's cost-benefit approach in *Entergy* decision, explaining that it was a reasonable interpretation of the statute. Nothing in the *Entergy* decision *mandates* a cost-benefit analysis, however. USEPA (and permitting authorities) may develop other reasonable interpretations of the statute to address site-specific criteria.

Alternative 1 would preclude any OTC facility from using the wholly disproportionate test in support of a request for alternative performance standards. All facilities would be required to comply with the proposed Policy through either Track 1 or Track 2. The State Water Board staff evaluated BTA, in part, using a "reasonably borne" cost analysis that developed estimates at the programmatic level. Because this document is equivalent to a Tier I analysis, it is not possible or practical to evaluate each facility's ability to comply with the performance standards in exhaustive detail. Excluding alternative compliance measures ignores the possibility that the Track 1 or Track 2 compliance cost might be unreasonable compared to overall benefits.

Alternative 2 would permit any OTC facility to use the wholly disproportionate cost test and request alternative performance standards. This alternative would likely encourage most facilities, if not all, to opt for this compliance strategy rather than following Track 1 or Track 2. The end result would be a BPJ, case-by-case permitting process that would return the full burden of implementing §316(b) to the Regional Water Boards and negate any benefits that a coordinated statewide policy would offer.

Alternative 3 permits any facility that operates a generating unit with a maximum heat rate of 8,500 BTU/kWh to request alternative, less stringent performance standards than Track 1 or Track 2. This alternative recognizes that some of the State's OTC units are relatively new and employ more efficient, less polluting technologies than the older conventional units that comprise the majority of the OTC units still in operation. Conventional steam boilers combust natural gas to produce steam, while more modern combined-cycle units employ a two-step process that first extracts energy from combustion and captures waste heat to generate steam. These units typically consist of two combustion turbines, a heat recovery steam generator (HRSG), and a steam turbine. The end result is a significant increase in overall energy efficiency since the same amount of fuel can produce up to 50% more electricity than a conventional steam boiler unit.

A unit's net plant heat rate (NPHR) is a common metric by which the relative fuel efficiencies of different units can be compared. The NPHR is expressed as the amount of energy (in BTU) required to produce one kilowatt hour of electricity (kWh) and can be used to calculate the overall unit efficiency using the following formula: $\%eff = \frac{3413}{NPHR} \times 100$

[118] USEPA Section 316(b) Phase II Economic and Benefits Analysis. 2002.

Plants with low maximum heat rates have higher thermal efficiencies. For example Haynes Unit 9 (a combined-cycle unit) has an average heat rate of 6,986 BTU/kWh and a thermal efficiency of 49%, while Haynes Unit 1 (a steam boiler unit) has an average heat rate of 10,786 BTU/kWh and a thermal efficiency of 32%. Combined-cycle units rank within the top 20% of all fossil-

Table 19. 2006 Average Heat Rates and Efficiencies

Facility	Unit	Average Heat Rate (BTU/kWh)	Efficiency (%)	Facility	Unit	Average Heat Rate (BTU/kWh)	Efficiency (%)
Alamitos	1	13,866	25	**Mandalay**	1	10,046	34
	2	12,897	26		2	9,758	35
	3	11,845	29	**Morro Bay**	3	9,619	35
	4	11,803	29		4	9,848	35
	5	10,549	32	**Moss Landing**	1A*	7,058	48
	6	10,819	32		2A*	7,027	49
Contra Costa	10	10,692	32		3A*	7,012	49
	9	11,280	30		4A*	7,001	49
El Segundo	3	10,954	31		6	9,660	35
	4	11,159	31		7	9,447	36
Encina	1	8,747	39	**Ormond Beach**	1	14,391	24
	2	9,174	37		2	9,940	34
	3	7,490	46	**Pittsburg**	5	10,506	32
	4	14,100	24		6	11,122	31
	5	11,426	30	**Potrero**	3	14,998	23
Harbor	10A*	9,007	38	**Redondo Beach**	5	21,440	16
	10B	8,834	39		6	19,942	17
Haynes	1	10,786	32		7	11,557	30
	2	10,637	32		8	10,801	32
	5	10,077	34	**Scattergood**	1	11,441	30
	6	10,348	33		2	11,050	31
	9*	6,986	49		3	10,185	34
	10*	7,056	48	**South Bay**	1	9,997	34
Huntington Beach	1	11,271	30		2	10,351	33
	2	13,580	25		3	10,820	32
	3	10,908	31		4	12,357	28
	4	11,039	31				

*Denotes a combined-cycle unit.

fueled units in terms of average heat rate and efficiency. Table 19, above, presents annual average heat rates and efficiencies for the State's fossil-fueled OTC units for 2006.[119]

The ability to generate electricity more efficiently translates to lower air emissions and lower intake water demands when expressed on a per MWh basis. That is, a combined-cycle unit will typically require less cooling water. Figure 17 presents the amount of cooling water required to produce one MWh, based on the unit's design intake capacity and boilerplate. On average,

[119] Calculated from USEPA Clean Air Markets data.

these combined-cycle units (in red) require approximately 50% less water than the average conventional fossil-fueled unit, and 67% less than the nuclear-fueled units.

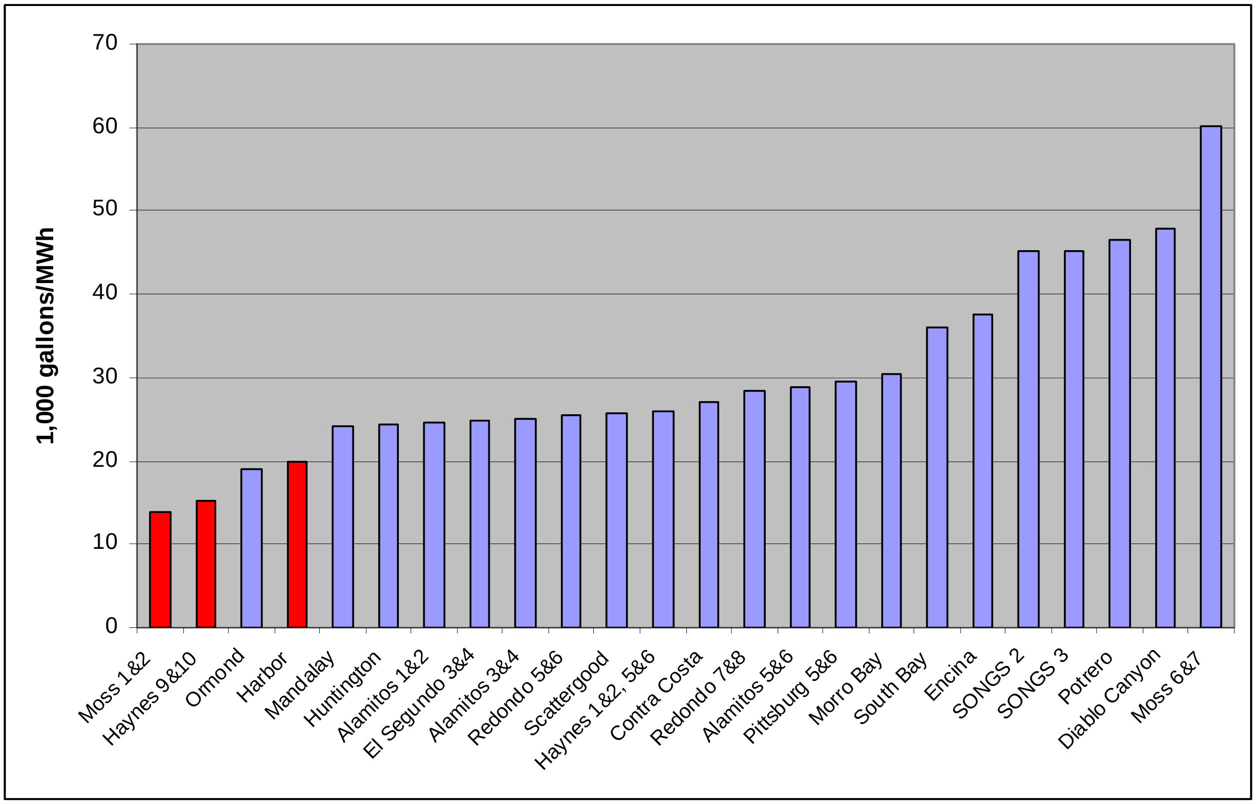

Figure 17. Design Cooling Water Demand

Likewise, combined-cycle units typically have lower air emission profiles for criteria pollutants than their conventional counterparts. As shown in Table 20, with the exception of total organic compounds (TOC), combined-cycle criteria pollutant emission factors are often significantly lower than conventional units.[120] Furthermore, because carbon dioxide (CO_2) emissions are directly related to the unit's energy efficiency, these emission factors are also considerably lower.

Lastly, Alternative 3 recognizes that the State's combined-cycle OTC units are relatively new compared with the remainder of the coastal fleet. Moss Landing Units 1 and 2 began service in 2002, while Haynes Units 9 and 10 came on-line in 2005. Harbor's combined-cycle unit is the oldest, having been placed into service in 1995. Large capital investments such as these are typically amortized over long periods (20 years or more) and have likely not been recouped yet. A detailed cost analysis would account for these investments when determining BTA and evaluate whether the Track 1 or Track 2 performance standards are cost-effective. The conventional steam units, on the other hand, have long since recouped their initial investments and no longer carry this additional financial burden.

Table 20 Average Air Emission Factors

[120] USEPA. Clean Air Markets Database. 2006.

	SO_2 (lbm/MWh)	NOx (lbm/MWh)	TOC (lbm/MWh)	ROG (lbm/MWh)	PM10 (lbm/MWh)	CO (lbm/MWh)	CO_2 (lbm/MWh)
Conventional	0.008	0.100	0.033	0.013	0.030	0.544	1,334
Combined-cycle	0.004	0.047	0.054	0.012	0.028	0.144	835

Notes:
SO2 = sulfur dioxide
NOx = nitrogen oxides
TOC = total organic compounds
ROG = reactive organic gases
PM10 = fine particulate matter (10 micros or less)
CO = carbon monoxide
CO2 = carbon dioxide

Alternative 4 permits the State's two nuclear facilities to request alternative, less stringent performance standards than Track 1 or Track 2. This alternative recognizes that compliance costs for nuclear units are uniformly higher, on a per-MWh basis, than for non-nuclear-fueled units. Table 21 presents initial capital costs developed for coastal OTC facilities in the Tetra Tech report, expressed as dollars per MW of generating capacity. Initial capital costs do not include added costs, such as energy penalty and any losses incurred if the facility must shutdown in order to install a closed-cycle wet cooling system.

Table 21. Initial Capital Costs

Facility	Cost (dollars/MW)
Alamitos	108
Contra Costa	144
Diablo Canyon	407
Harbor	56
Haynes	147
Huntington	131
Mandalay	97
Moss Landing	181
Pittsburg	92
SONGS	263

Diablo Canyon and SONGS are critical components of the State's electrical generating system, providing base-load capacity to more than four million households. Retrofitting these facilities to closed-cycle wet cooling would require taking these units offline for months to complete the retrofit project. During that time, replacement energy will need to be obtained, most likely from fossil fuel units that would increase overall air emissions, and possibly water withdrawals, depending on the replacement source. The energy penalty that would be incurred at Diablo and SONGS would require the permanent replacement of 220 to 250 MW of capacity, equivalent to one small conventional unit.

Alternative 4 recognizes the complexity of a retrofit application at these two facilities. While they may meet technical and logistical requirements for installing wet cooling towers, it may not be a practical option in light of the outsized importance of these facilities compared to others and the lengthy approval process that will be involved with the NRC and other interested parties. For these reasons, the provisions are included in the proposed Policy for Diablo Canyon and

SONGS to fund third-party studies that will investigate alternative compliance measures. These studies will be overseen by a review committee consisting of representatives from the State and Regional Water Boards as well as representatives from the environmental community and SCE and PG&E.

Alternative 5 combines components from Alternatives 1, 3, and 4. This Alternative 5 was not in the July 2009 draft version of this document, but was added by State Water Board staff to the final draft as the recommended alternative after consideration of public comment. Alternative 5 excludes a wholly disproportionate cost-benefit test, but provides alternative requirements for combined-cycle units and nuclear plants.

A requirement for a wholly disproportionate test would introduce a burden on Regional Boards to evaluate cost-benefit for combined-cycle units and nuclear plants. A cost-benefit test has the inherent problem of trying to monetize the value of marine life at the individual and ecological scales. As mentioned above, limiting benefits to commercially and recreationally important species (for which reasonable market data may be available) does not take into account the other impacted species that are not a part of the commercial or recreational fishery take. Commercial or recreational fishery species typically comprise less than 2% of the impinged and entrained organisms, therefore an analysis based on monetizing those species would ignore more than 98% of the other impacted fish and benthic invertebrates. In addition, with regard to commercial or recreational species, monetizing the impingement and entrainment does not take into account their ecological role, which can be very important.

State Water Board staff, however, recognizes existing combined-cycle units and nuclear plants as special cases requiring alternative requirements. Alternative 5 would not use a minimum thermal efficiency but rather would simply refer directly to existing combined-cycle units. Existing combined-cycle units, as stated above, are generally very energy efficient, produce lower air emissions for most pollutants and carbon dioxide, are more efficient in water use and therefore have fewer OTC impacts relative to electricity generated, and represent relatively recent capital expenditures. For these reasons, simply stating the alternate requirements in the policy, without requiring a complex and likely problematic cost-benefit test, would result in better statewide consistency and would reduce the burden on Regional Boards. The alternate requirements for combined-cycle units are recommended as follows:

The owner or operator of an existing power plant with combined-cycle power-generating units would be able to choose one of the following compliance options:

1. The owner or operator may count prior reductions in impingement mortality and entrainment associated with the replacement of steam turbine power-generating units by combined-cycle power-generating units, toward meeting Track 2 requirements for the entire power plant where those units are located. Prior reductions would be based on differences in NPDES permitted flows (before and after installation of combined cycle units) and evidence in the record of prior proceedings of the CEC and/or Regional Water Board; or

2. For combined-cycle power-generating units only, and not the facility as a whole, the owner or operator may reduce the through-screen intake velocity to a maximum of 0.5 ft/sec, and comply with the immediate and interim requirements (see Issue 3.12, above), for the life of those units.

For nuclear facilities, the alternate requirements would be the provisions to fund third-party studies (see Issue 3.3 above) that will investigate alternative compliance measures. As stated above, a review committee consisting of representatives from the State and Regional Water

Boards as well as representatives from SACCWIS, the environmental community, and SCE and PG&E would oversee these studies. The State Water Board would consider the results of the special studies, and subsequently evaluate the need to modify this Policy for nuclear plants. Criteria used in evaluating the need to modify this Policy would include:

1. Costs of compliance in terms of total dollars and dollars per megawatt hour of electrical energy produced over an amortization period of 20 years;

2. Ability to achieve compliance with Track 1 or Track 2 considering factors including, but not limited to, engineering constraints, space constraints, permitting constraints, and public safety considerations;

3. Potential environmental impacts of compliance with Track 1 or Track 2, including, but not limited to, air emissions; and

4. Any other relevant information.

If the costs for a nuclear plant to implement Track 1 or Track 2 are wholly out of proportion to the costs considered by the State Water Board in establishing Track 1 (i.e., a "cost-cost" comparison), then the Board may establish alternate requirements (see Section 5, Economic Analysis below for the costs associated with the staff recommended Track 1 BTA). A nuclear plant that demonstrates inability to achieve compliance with this Policy would still need to reduce impingement mortality and entrainment impacts to the extent practicable. The difference in impacts to marine life resulting from any alternative, less stringent requirements would need to be fully mitigated.

Staff Recommendation:
Staff recommends Alternative 5: Exclude a wholly disproportionate cost-benefit test, but provide alternative requirements for combined-cycle units and nuclear plants.

Policy Section(s):
Appendix A, Section 2.A (*Requirements for Existing Power Plants-Compliance Alternatives*)
Appendix A, Section 3.D (*Implementation Provisions-Nuclear-Fueled Power Plants*)

4.0 ENVIRONMENTAL EFFECTS AND MITIGATION

In California, protection of the State's water quality is entrusted by law to the State Water Board and the nine Regional Water Boards. As authorized by the Cal. Wat. Code, the State Water Board has adopted statewide water quality control plans and policies, such as the Ocean Plan and Thermal Plan. Consistent with and complementary to these statewide plans and policies, each Regional Water Board has adopted a Basin Plan that contains specific water quality standards and implementation provisions for its Region. The Regional Water Boards are primarily responsible for implementing statewide water quality control plans and polices together with their individual Basin Plans. In the current regulatory environment, the Regional Water Boards are also responsible for implementing §316(b) for existing facilities using BPJ on a site-specific basis.

Under Title 14, Cal. Code of Reg., §§15250 and 15251, certain agency actions can be certified as exempt from the CEQA requirements for preparing EIRs, negative declarations, and initial studies. They are not exempt from the other requirements of CEQA, including avoiding significant adverse effects on the environment wherever possible. Environmental analyses performed for such agencies may be used by other agencies in lieu of an EIR as long as specific requirements in Title 14, Cal. Code of Reg., §§15252 and 15253 are met. In such cases, the exempt agency is designated as the lead agency and the agency adopting the substitute document/analysis is designated as the responsible agency. The State Water Board is the lead agency for this project.

The water quality planning process of the Water Boards, by which the boards prepare, adopt, review, and amend the statewide and regional water quality control plans and policies, has been certified by the Secretary for Resources. While the planning process is exempt from certain CEQA requirements, it is subject to the substantive requirements in the Title 23, Cal. Code Reg., §3777, including a written report that describes the proposed activity, analyzes reasonable alternatives, and identifies mitigation measures that can minimize potentially significant adverse impacts.

§3777 also requires that the State Water Board complete an environmental checklist as part of the substitute environmental documentation. This section of the document discusses the different issue areas described in the CEQA checklist (Appendix B) for which State Water Board staff has identified potentially significant impacts, less than significant impacts, impacts that are less than significant with mitigation incorporated, or no impacts.

4.1 Reasonably Foreseeable Means of Compliance

Numerous technologies have been developed over the last several decades that attempt to minimize either impingement mortality or entrainment, or both. This section summarizes the basic characteristics of the more widely used technologies that can be used by the State's coastal OTC facilities to comply with the proposed Policy, either in whole or in part. The information presented below was compiled from multiple documents, principally the following:

- USEPA. T*echnical Development Document for the Final Section 316(b) Phase II Existing Facilities Rule*. EPA 821-R-04-007. February 12, 2004.
- EPRI. *Fish Protection at Cooling Water Intakes: Status Report.* TR-114013. 1999.

These reports provide additional detail on the function and design constraints of each technology.

Impingement mortality and entrainment technologies are often grouped according to their basic function:

- Flow Reduction: closed-cycle cooling; variable speed pumps
- Physical Barriers: traveling screens; cylindrical wedgewire screens (including fine mesh); nets; aquatic filter barriers
- Collection Systems: modified traveling screens with fish returns
- Behavioral Barriers: velocity caps
- Operational Modifications: intake relocation; seasonal operation

Most technology options that reduce entrainment can often be configured to reduce impingement mortality as well. Fine-mesh traveling screens, for example, are typically designed with the same collection and return system that also serves as an impingement mortality control. Likewise, aquatic filtration barriers will reduce both impingement and entrainment if they can be maintained properly. The same cannot be said for many impingement controls, such as barrier nets, velocity caps, or behavioral barriers, which cannot be configured to reduce entrainment.

Many facilities with once-through cooling systems employ some type of primary screening device to prevent larger debris from being drawn into the facility cooling system and damaging sensitive equipment. Vertical traveling screens are the most common screening technology used at California's coastal facilities. Traveling screens, as their name implies, consist of mesh panels fixed on a continuous loop that rotate through the water column and remove large objects from the intake forebay. Most often configured in a vertical orientation with slot sizes ranging from 3/8 inch to 1/2 inch, traveling screens typically rotate on a predetermined time cycle or based on a maximum pressure differential between the upstream and downstream faces of the screen panels. High-pressure sprays are used to remove debris from the screen, which is then disposed of in a landfill or returned to the source water. These screening systems are not designed to distinguish between debris and impinged fish and, due to their large slot sizes, do not offer any protection against entrainment.

4.1.1 *Closed-cycle Wet Cooling*

Closed-cycle wet 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 97% depending on various site-specific characteristics and design specifications. The environmental benefits associated with a closed-cycle system, through their reduced water use, may be substantial when compared to a once-through system but consideration must be given to other environmental impacts (air emissions, visual, noise, etc.) that may result from the use of a closed-cycle system and the comprehensive cost associated with its installation and operation. In a retrofit situation, where a wet cooling tower is proposed to replace a once-through cooling system, these impacts may be greater, and come at a higher cost, than for a facility that adopts closed-cycle cooling from the start.

Wet cooling towers are classified into two broad categories depending on the mechanism used to induce draft—the flow of cooler, drier air through the tower: natural or mechanical. Natural draft towers rely on the naturally-occurring chimney effect that results from the temperature difference between warm, moist air at the top of the tower and cooler air outside. Fans are not required to maintain the flow of air, but hyperbolic towers must be fairly tall to achieve the desired temperature differential. The overall height of these structures can approach 500 feet or more. Natural draft towers are more problematic for use at the State's OTC facilities due to the more stringent building code requirements for active seismic zones and the likely conflicts they would pose to scenic vistas in developed areas and near public recreation areas.

Mechanical draft cooling towers rely on motorized fans to draw air through the tower structure and into contact with the water. Without the same need for height as natural draft towers, the mechanical draft design presents a much lower visual profile against the surrounding area with typical heights ranging from 30 to 75 feet, depending on local constraints and design considerations. The overall area devoted to cooling towers, however, may be comparable to natural draft units since one mechanical draft unit, or "cell", has a smaller cooling capacity. Mechanical systems are arranged into multi-cell units, which are collectively referred to as the cooling tower, and can be placed in a single row (inline) or back to back. Although often more feasible, and in some cases more practical, than natural draft towers, mechanical systems place an added draw on the facility's net generating output in order to operate the fans that induce the draft. One of the State's OTC facilities—Pittsburg—operates a mechanical draft cooling tower for one of its units (Unit 7).

In the past, wet cooling towers were considered to be ill-suited for seawater applications due to the more corrosive effects of salt on construction materials, the degradation of the condenser performance due to scaling and the reduced rate of evaporation resulting from salt concentrations in the circulating water.[121] Advances in tower design and construction materials have enabled cooling towers to be successfully deployed in numerous locations with high salinity water. Table 22, below, reproduced from the Tetra Tech report, contains a list of facilities that have deployed wet cooling towers in high salinity environments.

Most cooling towers today, especially those in seawater environments, are built with materials that are more corrosion resistant than were used in the past (e.g., pressure treated wood) and designed for lower cycles of concentration (1.5) to minimize impacts from mineral buildup. This lower cycle of concentration, however, means that a cooling tower using seawater will require more makeup water than a cooling tower using freshwater. All of the State's coastal OTC facilities currently use seawater or brackish water for cooling and would likely continue to use the same source water to provide makeup water. In a few cases, it may be possible to use reclaimed water instead.

The CEC commissioned a study evaluating the performance and environmental effects associated with salt water cooling towers. The report found that with proper design and maintenance, wet cooling towers can be installed and operated in saltwater environments.[122] Fiberglass reinforced plastic and prestressed concrete cylinder pipe suitable for a seawater application are the industry standard materials for use in saltwater cooling towers.

Table 22. Installation of Seawater/Saltwater Cooling Towers

Location	Project Owner	Design Flow (MGD)	Installation Year
Oklahoma, USA	Oklahoma Gas & Electric Company	87	1953
Kansas, USA	American Salt Company	7	1964
New Jersey, USA	Exxon Chemical Company	32	1968
Stenungsund, Sweden	ESSO Chemical AB	146	1969
Judibana Falcon, Venezuela	Lagoven Amuay	49	1970
Okinawa, Japan	Exxon Petroleum Company	21	1971
Florida, USA	Gulf Power Company	239	1971
Texas, USA	Dow Chemical Company	87	1973
Maryland, USA	Potomac Electric Power Co. Plant 3	376	1974
Virginia, USA	Virginia Electric Company	477	1975
North Carolina, USA	Pfizer Company	79	1975
California, USA	Dow Chemical Company	17	1976
Washington, USA	ltalco Aluminum Company	59	1976
California, USA	Pacific Gas & Electric Company	538	1976
Texas, USA	Houston Lighting & Power Company	347	1977
Mississippi, USA	Mississippi Power Company	250	1980

[121] Ying, B.Y and David Suptic. 1991. *The Use of Cooling Towers for Salt Water Heat Rejection*. The Marley Cooling Tower Co. Overland Park, KS.

[122] CEC. Cost, Performance, and Environmental Effects of Salt Water Cooling Towers. 2007.

Location	Project Owner	Design Flow (MGD)	Installation Year
Maryland, USA	Potomac Electric Power Co. Plant 4	376	1981
Arizona, USA	Palo Verde I Plant	849	1985
Arizona, USA	Palo Verde II Plant	849	1986
Florida, USA	Stanton Energy #I Station	289	1986
Arizona, USA	Palo Verde Ill Plant	849	1987
Texas, USA	Houston Lighting & Power Company	348	1987
Delaware, USA	Delmarva Power & Light	293	1989
California, USA	Delano Biomass Energy Company	28	1991
Florida, USA	Stanton Energy #2 Station	289	1995

4.1.2 *Closed-cycle Dry Cooling*

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 wet cooling systems—such as adverse impact on aquatic ecosystems, consumptive use of water resources, and plume or drift emissions.

The use of dry cooling systems at steam electric power plants began largely as an alternative to once-through or wet cooling systems in areas where water resources were limited, but their application has expanded over the years in response to other environmental concerns related to the withdrawal and discharge of large volumes of cooling water. While many of the existing applications of dry cooling in the United States are limited to smaller capacity facilities (less than 150 MW), larger projects are increasing in frequency as regulatory and market pressures minimize some of the disadvantages usually associated with these types of systems. In California, Otay Mesa (510 MW), Sutter (540 MW), and Gateway (530 MW) are examples of larger applications of dry cooled units that have been built, or are underway, in the last decade. Encina Power Station and El Segundo Generating Station (Units 1 and 2), have each proposed to repower units at their facilities and convert the existing once-through cooling systems to dry cooling.

An optimally designed dry cooled system uses an air cooled condenser rather than the shell and tube surface condenser that is used in both OTC facilities and those with wet cooling towers. Dry cooled systems that are designed to operate with surface condensers are significantly less efficient than those with an air cooled condenser. Theoretical heat rate increases with dry cooling would be two to three times higher than with wet cooling, in a retrofit application.

As noted above, wet cooling retrofits can reduce IM/E impacts by as much as 97% over OTC. Dry cooling would effectively eliminate cooling water withdrawals but would result in significant increases in greenhouse gas and criteria pollutant emissions due to the significantly greater efficiency losses. Dry cooling systems have never been used as a technology option to retrofit existing OTC facilities, although they remain a preferred technology when a facility chooses to repower an existing unit, or for new units.

4.1.3 *Barrier Nets*

Fish barrier nets are constructed of wide-mesh fabric panels and configured to completely encircle the cooling water intake structure inlet from the bottom of the water column to the surface. The relatively large slot sizes (1/2 inch) combined with the larger overall area of the net reduce impingement mortality by preventing physical contact with the main intake structure and by maintaining a low through-net velocity (typically 0.2 ft/sec or less), which prevents organisms from being drawn against the net. Fish barrier nets have been deployed most successfully in locations where seasonal migrations create high impingement events, and their use can be limited to these same periods. Seasonal use avoids damage that may be caused by winter icing or high waves. Impingement mortality reductions have exceeded 90% at some locations. The large openings do not offer any protection against entrainment.

Barrier nets are most effective in areas that have relatively calm water and would not be impacted by strong currents, winter storms and wave overtopping. These conditions could be expected at facilities with open ocean intakes, but may be more practical in estuary and enclosed bay settings, such as Pittsburg and Contra Costa in the Sacramento/San Joaquin Delta. Barrier nets may also be applicable in harbor settings, although they would have to be evaluated for potential conflicts with other uses such as shipping, boating, swimming, or recreational and commercial fishing.

4.1.4 *Aquatic Filtration Barriers*

Aquatic filtration barriers are fabric panels constructed of small-pore (less than 20 microns) materials and deployed in front of an intake structure much like a barrier net. The small openings in the fabric allow water to pass through while screening out most organisms, including those that are susceptible to entrainment. The small openings reduce the through-fabric flow rate to a maximum of 10 gpm per square foot, as opposed to 25–27 gpm per square foot for barrier nets. At a given facility, an aquatic filtration barrier will be approximately 2.5 times larger than a barrier net and require a larger open area for placement. The smaller openings are also more susceptible to fouling and clogging by sediment or debris and require a more active maintenance effort to minimize performance losses. An aquatic filtration barrier deployed in marine or brackish waters, where clogging and fouling is more of a concern than in a freshwater environment, would likely operate below its design maximum and further increase the initial size of the system required to reliably provide sufficient water to the facility.

To date there has been only one deployment of an aquatic filtration barrier at a facility with a large intake volume comparable with the facilities in this study. The Lovett Generating Station, located on the Hudson River in New York, with an intake capacity of 391 MGD, has conducted a comparative evaluation of a seasonally-deployed aquatic filtration barrier between one protected and one unprotected intake in different configurations since 1995. Impingement reductions have been substantial, with observed reductions of 90% or better. Entrainment has consistently been reduced by 80%, compared to the unprotected intake that serves as the baseline. Wave overtopping and screen fouling present the greatest challenges to maintaining the system at its optimal level of performance.[123]

Contra Costa had initially proposed to conduct an aquatic filtration barrier evaluation, but the project was halted due to maintenance difficulties.[124] In its 2005 Proposal for Information Collection, El Segundo proposed a pilot study of a submerged aquatic filtration barrier configuration, although no action has been taken.[125] If local conditions can be met, aquatic

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[123] Lawler, Matusky & Skelly Engineers. ***Lovett 2000 Report***. Prepared for Orange and Rockland Utilities, Inc. 2000.
[124] CEC. ***Issues and Environmental Impacts Associated with Once-Through Cooling at California's Coastal Power Plants.*** CEC-700-2005-013. 2005.
[125] El Segundo, LLC. Proposal for Information Collection—El Segundo Generating Station. November 17, 2005.

filtration barriers would be expected to reduce impingement and entrainment to levels comparable with reductions observed at Lovett.

4.1.5 *Intake Relocation*

Cooling water intakes that are located at an ocean shoreline or within an estuary are thought to have a greater environmental impact due to their presence in more biologically productive areas. In principle, it is thought that relocating an intake to a deep offshore location out of the euphotic zone will result in lower IM/E potential due to the lower densities of impingeable and entrainable organisms. USEPA recognized this distinction in the Phase II rule when it defined a baseline facility as one located flush with the shoreline at the surface, but acknowledged the limited data available that supported this claim and the need to evaluate each installation on a case-by-case basis. The potential benefit would need to be assessed with detailed studies enumerating the relative densities and species makeup at the shoreline and proposed offshore location. Relocating the intake to an offshore location may result in impingement and/or entrainment of different species, exchanging one problem for another.

Six of the facilities in this study already have a deep offshore intake in conjunction with a velocity cap (Ormond Beach, Scattergood, El Segundo, Redondo Beach, Huntington Beach, and SONGS). Relocation may be applicable at South Bay (into the Pacific Ocean), Encina, Haynes, Alamitos, Mandalay, Diablo Canyon and Moss Landing. Costs associated with relocation, however, may be prohibitive, particularly for those facilities where the offshore bathymetry is rocky and steep.

4.1.6 *Velocity Caps*

Offshore intakes may be fitted with a device known as a velocity cap, which is a physical barrier placed over the top of an intake pipe rising vertically from the sea floor. Water is drawn into the pipe through openings placed on the sides of the cap, which converts what had been a vertical current to a horizontal one. Motile fishes are less likely to react to dramatic changes in vertical currents, but exhibit a more consistent flight response when the changes are sensed in the horizontal current, thus preventing their capture by the intake system. Velocity caps are classified as an impingement reduction technology because they function by discouraging "impingeable" fishes from entering the system. Velocity caps offer no reduction in the rate of entrainment, except as may be gained by differences in types and concentrations of entrainable organisms between the shoreline and the offshore location of the velocity cap.

Ormond Beach, Scattergood, El Segundo, Redondo Beach, Huntington Beach, and SONGS currently employ offshore intakes with velocity caps for their cooling systems. While the impingement reductions can be substantial, performance may vary unexpectedly. Studies at Huntington Beach and El Segundo have shown impingement reductions ranging as high as 90%. SONGS operates two separate intake structures that are essentially mirror images of each other. The intakes for Units 2 and 3 are located offshore with velocity caps in relative proximity to one another at similar depths and bathymetry. Impingement data for 2003, however, showed more than 2.5 million fish impinged at Unit 3, a rate nearly 2.5 times that for Unit 2.[126] LADWP recently conducted a velocity cap evaluation at Scattergood. Impingement effectiveness was shown to be better than 95%.[127]

[126] SCE. *Proposal for Information Collection—San Onofre Nuclear Generating Station*. October 2005.
[127] LADWP. *Clean Water Act Section 316(B) Velocity Cap Effectiveness Study*. June 28, 2007.

4.1.7 *Variable Frequency Drives*

A variable frequency drive (similar to variable speed pumps) allows a facility to lower the cooling water withdrawal rate by reducing the electrical load to the pump motor. The pump speed can be tailored to suit the cooling water demands at a certain time or under certain conditions. Variable frequency drives can throttle a pump's flow rate more precisely according to operating conditions, but must operate at a minimum flow rate in order to maintain sufficient head and prevent damage to the pump from cavitation. Depending on the initial design specifications, variable frequency drives can achieve flow reductions ranging from 20-50% of their maximum capacity.

Actual flow reductions with a variable frequency drive vary throughout the year depending on seasonal conditions and facility operations. At their maximum efficiency, variable frequency drives enable a facility to withdraw the same volume of water as conventional circulating water pumps, thereby negating any potential benefit. Base-load units would not be ideal candidates for this technology, since they operate in the upper range of their load capacity for significant portions of the year. Units that are designated for peak or intermittent dispatch are more likely to accrue benefits from this method of flow reduction. In these situations, the use of variable frequency drives must be evaluated against the operational profile of that facility and any seasonal variations in the makeup or abundance of affected species in the water body.

A facility that employs variable frequency drives may be able to reduce its intake flow by 50% on an annual basis, but may operate at its maximum capacity during the most critical periods of the year, i.e., during spawning or migration seasons. An annual flow reduction might be a suitable metric if the potential for impact is equally distributed throughout the year. This method skews the actual benefit, however, if 80% of the potential annual impact occurs within a short time period that also corresponds to maximum pump operation.

At Contra Costa Power Plant, for example, variable frequency drives are installed on the circulating water pumps for Units 6 and 7. From May 1 to July 15, which overlaps with periods of striped bass larval abundance, operating procedures call for the variable frequency drives to operate at 50% capacity until the unit is generating a 172 MW load. Above that threshold, the pumps gradually increase the intake flow until they reach 95% of the maximum capacity. Depending on the amount of time in operation and the corresponding generating load, variable frequency drives may reduce intake volumes by as little as 5%.[128]

4.1.8 *Seasonal Operation*

Seasonal operation may allow for significant reductions of impingement and entrainment at non-baseload facilities, provided the operational period does not overlap with times of highest impingement and/or entrainment susceptibility in the affected water body. The limitations associated with seasonal operation are similar to the issues concerning the use of variable frequency drive, discussed above.

4.1.9 *Fine-Mesh Cylindrical Wedgewire Screens*

Fine-mesh cylindrical wedgewire screens reduce impingement by maintaining a low through-screen velocity (0.5 ft/sec), which allows larger organisms to escape the intake current. Entrainment is reduced through the use of screen mesh with slot sizes small enough to prevent eggs and larvae from passing through. The phenomenon of hydrodynamics resulting from the

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[128] Mirant Delta, LLC. *Clean Water Act Section 316(b) Proposal for Information Collection for Mirant's Contra Costa Power Plant*. 2006.

cylindrical shape of the screen aids in the removal of small "entrainable" organisms that become caught against the screen. The low through-screen velocity is quickly dissipated and allows organisms to escape the influence of the system, provided there is a sufficient ambient current present to carry freed objects away from the screen. Organisms that are impinged against the screens are released through the action of a periodic airburst cleaning system and carried away by the ambient current.

Alden Research Laboratories, in coordination with EPRI, conducted laboratory evaluations of the effectiveness of fine-mesh cylindrical wedgewire screens using screens with different slot sizes and through-screen velocities. Reductions approached 100% for impingement and 90% for entrainment, depending on the specific design conditions.[129] These reductions compare favorably to results from facilities that have deployed or tested fine-mesh cylindrical wedgewire screens for entrainment.

In the Phase II rule, USEPA determined that fine-mesh cylindrical wedgewire screens used at certain freshwater river facilities with sufficient ambient current and a through-screen velocity of 0.5 ft.sec or less could be installed as a pre-approved technology capable of complying with the BTA performance standard. While this approval was only extended to certain facilities, it was not precluded from use at other locations.

The near-shore currents found at coastal facilities are less easily predicted and can slacken or change direction along with the tide, potentially impacting the ability of the screens to remain free of debris and impinged organisms. Without a consistent current, screens may quickly clog and impact the performance of the facility. The distance from shore that would be required (2,000 feet or more) further complicates the use of wedgewire screens because the ability to maintain sufficient air pressure for the airburst cleaning system decreases substantially at those distances, and they cannot be assured to function at all times.

The applications for this technology are increasing, however, with new installations in the Great Lakes and elsewhere. In California, fine mesh cylindrical wedgewire screens may be a practical alternative at facilities that can meet the minimum design criteria. The Tetra Tech report developed a conceptual application for Pittsburg and Contra Costa based on minimum distance requirements and sufficient ambient currents in the source water.

4.1.10 *Modified Traveling Screens (Ristroph Screens)*

Vertical traveling screens, such as those at most of California's facilities, can be modified to capture and remove fish that are impinged against the screens and return them to the source water body without inducing serious injury or mortality. The term "Ristroph screens" refers to a particular modification where individual screen panels are fitted with water-filled buckets that collect fish temporarily. As the screens rotate, the buckets empty into a return trough or pipeline that is flushed with water to carry the captured fish back to the source. A low-pressure spray is employed to gently remove any organisms that remain impinged on the screens and send them to the return trough, followed by a high-pressure spray to remove other debris. The critical design elements of this system include the screens' rotation speed, the material and shape of the collection buckets, and the method of return to the water body. Ristroph screens designed to reduce impingement mortality are relatively easy to install and do not involve substantial

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[129] Amaral, S., D. Dixon, M. Metzger, J. Black, and E. Taft.. Laboratory Evaluation of Cylindrical Wedgewire Screens. Presented at the *Symposium on Cooling Water Intake Technologies to Protect Aquatic Organisms*, sponsored by U.S. Environmental Protection Agency, Crystal City, VA. May 6–7, 2003.

modification to the existing intake structure. The principal new component is usually the fish return system.

Modified traveling screens have been shown to reduce impingement by up to 90% or more. Common to most of these applications is the need to tailor the final design and operation of the system to the unique mix of species and hydrodynamic conditions at each facility. Factors ranging from the screen and collection bucket material to the speed at which the screens are rotated can directly affect the overall effectiveness, which may vary from species to species. Hardier species may exhibit higher latent survival rates than smaller, more fragile species.

These systems can be fitted with fine-mesh panels to reduce the entrainment of eggs and larvae as well. Screen slot sizes typically need to be within the range of 1–2 millimeters order to be effective as an entrainment reduction measure, although the size used at a particular location is dependent on the target species. With a smaller open area per square foot than standard screens, fine-mesh screens require a larger overall intake structure in order to maintain desirable intake velocities. The need to expand the intake structure to accommodate the new screens may result in a temporary shutdown.

Entrainment reductions can also range as high as 90% or more when fine-mesh panels are used in conjunction with a return system. What is less understood, however, is the viability of eggs and larvae following their impingement against a fine-mesh screen and their return to the water body. Few studies have been conducted that evaluate viability, primarily because of the smaller number of facilities that have adopted fine-mesh traveling screens. Screened organisms, although they have been prevented from being entrained through a cooling water system, may suffer serious injury or mortality, which effectively results in the same adverse impact.

4.2 POTENTIAL ADVERSE ENVIRONMENTAL EFFECTS

Title 23, Cal. Code Reg., §§ 3720-3782 require the State Water Board to evaluate potential environmental impacts that may be caused by complying with the proposed Policy with one or more of the reasonably foreseeable compliance methods. Potential impacts to the following resource areas, at a minimum, must be addressed:

- Aesthetics (Issue 1)
- Agriculture (Issue 2)
- Air Quality (Issue 3)
- Biological Resources (Issue 4)
- Cultural Resources (Issue 5)
- Geology and Soils (Issue 6)
- Hazards and Hazardous Materials (Issue 7)
- Hydrology and Water Quality (Issue 8)
- Land Use Planning (Issue 9)
- Mineral Resources (Issue 10)
- Noise (Issue 11)
- Population and Housing (Issue 12)
- Public Services (Issue 13)
- Recreation (Issue 14)
- Transportation and Traffic (Issue 15)

- Utilities and Service Systems (Issue 16)
- Mandatory Findings of Significance (Issue 17)

This section presents the rationale for the ratings of environmental impacts identified in the CEQA checklist (Appendix B) and any potential mitigation measures. Each resource area is evaluated according to one of four categories:

- *Potentially Significant* applies when there is substantial evidence an impact will be significant.
- *Less than Significant with Mitigation Incorporated* applies where the State Water Board incorporates mitigation measures that will reduce the effect from Potentially Significant to Less than Significant.
- *Less than Significant* applies where the effect will not be significant and mitigation is not required.
- *No Impact*.

State Water Board staff evaluated the potential environmental effects of the compliance methods described in Section 4.1 in two general categories: closed-cycle wet cooling and alternative technologies. Staff divided these technologies in recognition of the substantial difference between closed-cycle cooling and all other IM/E technologies, most of which are "front-of-pipe" technologies that screen or otherwise divert organisms from coming in contact with the intake structure. Closed-cycle cooling, on the other hand, involves a substantial reworking of a facility's cooling system and has a greater potential to cause an environmental impact.

Staff did not identify any potential impacts for alternative technologies and operational measures (fine mesh screens, barrier nets, fish return systems, wedgewire screens, velocity caps, offshore intakes, variable speed pumps and seasonal operation). These technologies, if effective at a particular location, can be implemented without any adverse impacts.

This section, therefore, discusses the identified adverse impacts as they relate to retrofitting any existing OTC unit with closed-cycle wet cooling. Dry cooling is not considered a viable technology option in a retrofit application; it is more commonly used at new or repowered units. Because the project will affect only 19 individual facilities, impacts are generally localized for most resource areas. When feasible, the impacts are discussed at the facility level.

Issues for which no impacts were identified are not discussed in detail. These issues include

- Cultural Resources (Issue 5)
- Geology and Soils (Issue 6)
- Hazards and Hazardous Materials (Issue 7)
- Land Use Planning (Issue 9)
- Mineral Resources (Issue 10)
- Utilities and Service Systems (Issue 16)
- Mandatory Findings of Significance (Issue 17)

4.3 AESTHETICS

Aesthetic impacts comprise the adverse effects a project might have on the scenic quality and visual characteristics of public recreation areas, historically significant sites, or scenic highways. This may also include a significant degradation of the existing visual attributes that are closely linked to a facility's surroundings and topography by introducing prominent structures or features such as cooling towers or substantial light sources. Visual impacts are largely determined subjectively by the individual observing a particular area or viewshed, although objective qualities can also inform the analysis. The potential impact that a project might have on overall visual quality is evaluated against a particular setting's attractiveness, coherence and the presence of unique and popular vistas of geological, topographical or biological resources. Consideration must also be given to the designated uses of the immediate vicinity and local zoning laws, ordinances, regulations, and standards.

Potential Impacts

Mechanical draft wet cooling towers could introduce new, large structures to a particular location, with the total required area dependent on the cooling demand and different configuration possibilities at the site. The Tetra Tech report estimated that wet cooling retrofits at the coastal OTC facilities would require anywhere from 75 to 90 square feet per MW of capacity for conventional steam units, with up to 168 square feet for Diablo Canyon and SONGS and as little as 46 square feet required for combined-cycle units.

A wet cooling tower must provide a certain volume in which air and water can interact to achieve the desired cooling level and, as such, can vary in terms of their height-to-footprint ratio (defined as the height compared to the length times the width). The overall tower height is a function of how much space is available at a particular location, although shorter towers are generally preferable in that they present a much a much lower visual profile and require less pumping capacity (and less energy). The overall mechanical draft tower height may range from 35 to 65 feet depending on site constraints. By comparison, natural draft towers can be as tall as 500 feet or more, although they generally occupy a smaller footprint for the same cooling capacity.

Wet cooling towers can also produce a visible plume—a column of condensed water vapor resulting from the exhaust's higher temperature and saturation level relative to the ambient atmosphere. Visible plumes are typically more pronounced during winter months, although cool, humid conditions may also produce a substantial plume at any time of the year. When present, plumes can rise several hundred feet above the tower and contribute to cloud or fog formation that can block sightlines. On sunny days, plumes can create large shadows that can persist for hours or days depending on meteorological conditions. This may be undesirable if located near commercial or residential areas, or areas designated for public recreational use.

Mitigation Measures

Visual impacts associated with the wet cooling tower's presence at a particular location can be mitigated through compliance with local building codes that establish building height limits and minimum setback requirements. Local codes may also include mitigation measures designed to obscure a structure's physical presence by requiring natural barriers or vegetation to blend in with the surrounding area. The Tetra Tech report identified building height and setback requirements for all of the facilities where wet cooling towers were considered feasible and developed a conceptual design that complies with local codes.

Technologies and design measures can reduce a visible plume's size and frequency to a level that is considered insignificant for aesthetic impacts. The most common approach incorporates a smaller dry-cooled component above a conventional wet tower to raise the exhaust temperature and reduce its humidity below the ambient atmosphere's saturation point. The resulting plume is dramatically smaller than an unabated plume, often to the point that it is unnoticeable.

Plume-abated, or hybrid, cooling towers are subject to more restrictive siting criteria than a conventional wet tower, however, and can raise the overall tower height by 10 to 20 feet or more. Additional height requirements can also be mitigated, however, depending on the amount of space available at a particular location. Hybrid towers are more susceptible to the effects of exhaust recirculation and must be located at sufficient distances from other towers and obstructions and thus cannot be configured in a back-to-back arrangement that minimizes space requirements. The initial capital cost of plume-abated towers is typically two to three times higher than conventional (unabated) towers, but is unnecessary at most facilities subject to the proposed Policy.

Assessment
Staff did not identify any significant aesthetic impacts for most of facilities subject to the proposed Policy because they are already located in areas with large, industrial structures that predominate in the immediate vicinity, or are located in remote areas that do not have use levels significant enough to warrant concern. Other facilities were identified as having less than significant impacts provided the appropriate mitigation measures are adopted because of their proximity to popular recreation areas (El Segundo, SONGS, and Scattergood) or commercial and residential areas (El Segundo and Morro Bay).

4.4 Agricultural and Forest Resources

Impacts to agricultural and forest resources can result if a project causes agricultural and forest land to be converted for other uses, conflicts with local zoning ordinances or contributes to changes in the surrounding environment that inhibits or interferes with existing agricultural and forest uses.

Potential Impacts
Small water droplets are ejected from the cooling tower as part of the exhaust, some of which may evaporate prior to settling on the surrounding area as drift. In marine or estuarine environments, these droplets might have salinity levels that are 50% higher than the source water (up to 53 parts per thousand) and can settle on nearby structures and vegetation. Under average conditions drift does not carry very far from the originating source and would require sustained high winds and high humidity to reach distances of several hundred feet in any significant quantity. Salt deposition from drift may affect particular crops in a few limited circumstances, but the concern has generally proven to be unwarranted.[130]

Mitigation Measures
Drift elimination serves a dual purpose: reduce salt deposition and reduce fine airborne particulate matter. Drift from wet cooling towers can be mitigated by installing drift eliminators immediately prior to the tower's exhaust point. This technology consists of materials shaped into lattice or herringbone configuration designed to capture airborne water droplets before they can exit the tower. Current drift elimination technology can reduce the drift volume to 0.0005% of the circulating water flow, or approximately 0.5 gallons per 100,000 gallons. Although there are no requirements for drift emissions from wet cooling towers, drift eliminators are considered

[130] CEC. Cost, Performance, and Environmental Effects of Salt Water Cooling Towers. 2007

Best Available Control Technology (BACT) for fine particulate emissions from mechanical draft wet cooling towers.

Assessment
Staff did not identify any significant agricultural or forest impacts for any of the facilities subject to the proposed Policy, but has included a discussion of this issue because it is frequently cited as a concern with closed-cycle wet cooling systems. N o agricultural or forest areas were identified in close enough proximity to potentially warrant concern over drift deposition. The Tetra Tech report, however, assumed high efficiency drift eliminators would be included for all facilities where wet cooling towers were considered feasible.

4.5 AIR QUALITY

New Source Performance Standards (NSPS) are technology-based limitations that are imposed on certain new or modified air pollution source categories. USEPA has promulgated NSPS for (1) fossil fuel–fired steam generators built or modified after August 17, 1971, and (2) fossil fuel–fired steam generators built or modified after September 18, 1978. Both apply to new or modified units with thermal input rates greater than 250 million BTU/hr (MMBTU/hr), and both strictly control PM_{10}. Emission sources built prior to 1971 are exempt from the NSPS unless they are modified or reconstructed. NSPS regulations are more general than New Source Review (NSR) requirements and are based on what is technologically and economically feasible within an industrial category.

NSR requirements are more site and project-specific than NSPS requirements and allow state regulating authorities to set stricter limitations based on what they determine to be the best technology currently available. The Clean Air Act designates “major emitting facilities” that are subject to the NSR program, including fossil fuel–fired steam electric plants of more than 250 MMBTU/hr heat input that emit, or have the potential to emit, 100 tons per year or more of any air pollutant. The NSR program then distinguishes between areas where National Ambient Air Quality Standards are met and nonattainment areas.

Major emitting sources in attainment areas that are being constructed or modified must undergo Prevention Of Significant Deterioration permitting and must implement the Best Available Control Technology (BACT). In nonattainment areas, the Lowest Achievable Emissions Rate (LAER) applies to such sources. BACT and LAER are technology-based standards and must be as stringent as, or more stringent than, the applicable NSPS emission limitation.

For existing plants to trigger NSPS or NSR, two criteria must be satisfied: (1) there must be a physical or operational change and (2) there must be a significant net emissions increase. USEPA defines “significant net emissions increase,” differently for the two programs, using a total annual emissions test (in tons or kilograms per year) in the NSR program and using an emissions rate test (in tons or kilograms per hour) for NSPS purposes. If a modification results in an increase in emission rate to the atmosphere of any pollutant to which a standard applies, the source must comply with the NSPS requirements for its industrial category.

Retrofitting power plants from OTC to wet or dry cooling will cause decreases in net plant efficiency and increases in auxiliary energy 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 10 microns or less (PM10)] and carbon dioxide (CO_2) emissions produced by the combustion of additional fuel.

Potential impacts are divided into two main categories for air quality: (a) stack emission of criteria pollutants and carbon dioxide, and (b) fine particulate matter emissions from wet cooling towers.

4.5.1 *Increased Stack Emission of Criteria Pollutants and Carbon Dioxide*

A facility that retrofits to closed-cycle cooling will experience a loss in thermal efficiency and an increased parasitic (or onsite) electrical demand to power new equipment. While a retrofitted facility will experience increased stack emissions on a per-kWh basis, the total mass emission may not change depending on how the facility chooses to modify its operations to mitigate the changes.

Energy Penalty

A thermal electric power plant's ability to generate electricity efficiently is based, in part, on how readily it can reject waste heat to the environment, thus maintaining optimal backpressure at the steam turbine's exhaust point. When a facility converts from OTC to closed-cycle, the cooling water inlet temperature will rise and affect the condenser's ability to reject waste heat from the system. This translates to greater resistance against the turbine and requires additional fuel to produce the same amount of electricity (i.e., the facility's heat rate [BTU/kWh] will increase). Thermal efficiency losses are expressed as a percentage reduction from the design operating conditions.

A retrofitted facility will also need to consume additional electricity to operate the tower's fans and additional circulating water pumps, if it is a closed-cycle wet system. The net result is a reduced amount of electricity available for sale and can be expressed as a proportional change in the facility's heat rate. Together, thermal efficiency losses and increased onsite demand comprise the energy penalty, expressed as a percentage of the facility's nameplate generating capacity.

Figure 18 summarizes cumulative energy penalty estimates for coastal OTC presented in the Tetra Tech report based on retrofitting to closed-cycle wet cooling. Together, these penalties would have resulted in a loss of over two million MWh based on 2006 generating data. Energy penalties estimates for dry cooling retrofits were not developed for OTC facilities, but would be approximately twice as high.

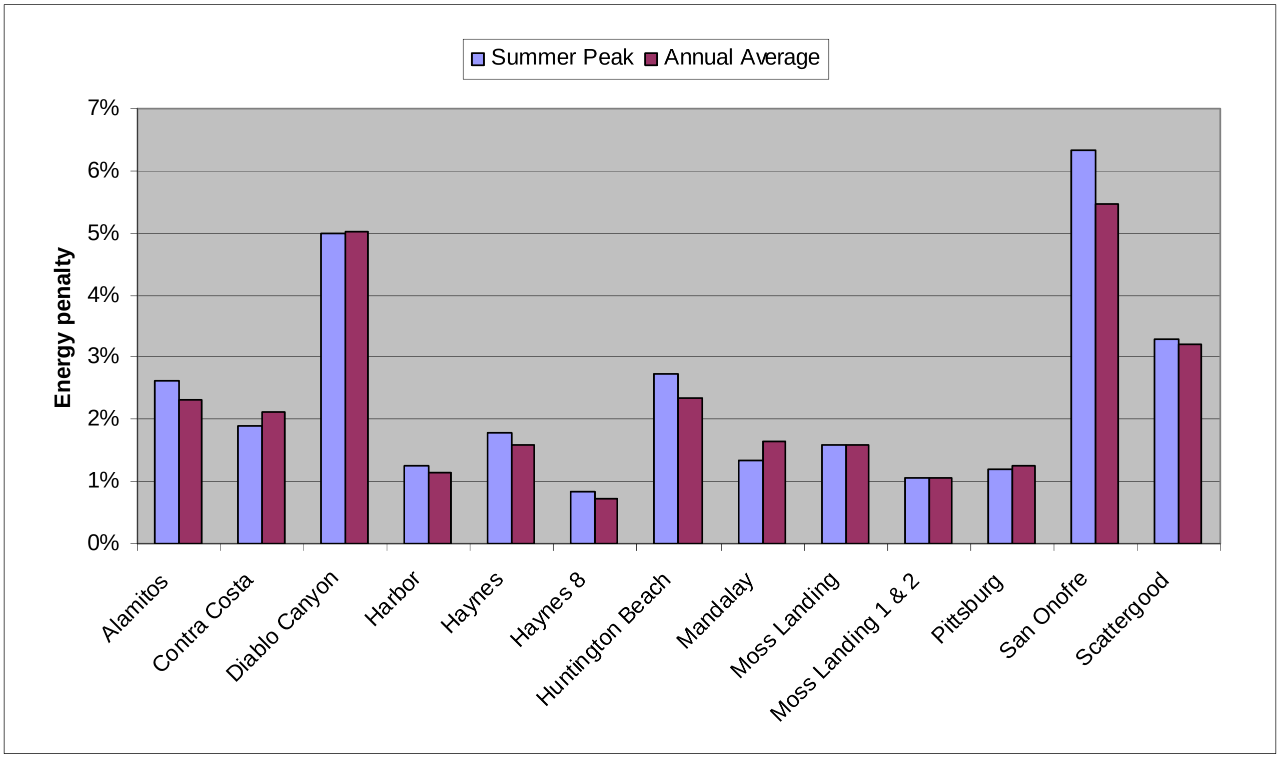

Figure 18. Cumulative Energy Penalties for Wet Cooling Tower Retrofits

Criteria Pollutants and CO2
The efficiency losses described above will result in higher stack emissions of criteria pollutants and carbon dioxide on a per-kWh basis, although the cumulative mass loading will depend on what sources are used to replace the generation shortfall. In some cases, natural gas steam boiler units may be able to increase the thermal input to the unit (i.e., burn more fuel) to compensate for the decreased efficiency ("native replacement"), although the ability to do so is dependent on several factors not quantified here. Alternatively, the shortfall may be replaced by non-native sources that have excess generating capacity available. Diablo Canyon and SONGS do not have the option to generate additional electricity onsite and must procure any lost output from external sources.

It is not possible to accurately determine how facilities will address the energy penalty, nor can replacement sources for Diablo Canyon and SONGS be identified. Replacement energy may come from any mix of native and non-native fossil fueled generators as well as renewable sources. Staff developed multiple implementation scenarios to describe the range of potential air emission increases that might result from retrofitting OTC facilities to closed-cycle wet systems based on 2006 emissions data from USEPA's Clean Air Markets database.

Scenario 1: All units deemed feasible are retrofitted to closed-cycle wet cooling, with native replacement for fossil units. The generating shortfall from Diablo Canyon and SONGS is assumed to be replaced by excess capacity within the coastal fleet (see Table 23, below).

Table 23. Estimated Stack Emission: Scenario 1

	Shortfall (MWh)	SO_2 (tons)	NO_2 (tons)	CO_2 (tons)	CO (tons)	TOG (tons)	ROG (tons)	PM10 (tons)
Baseline	--	53	557	9,070,258	3,116	413	116	262
Retrofitted Fossil Increase	295,826	1	11	175,046	71	7	2	5
Retrofitted Nuclear Increase	1,824,732	7	89	1,062,213	450	39	12	28
Net Increase	**--**	**15%**	**18%**	**14%**	**17%**	**11%**	**12%**	**13%**

Scenario 2: All units deemed feasible retrofitted to closed-cycle. All generation shortfall is replaced by new combined-cycle units, which are more efficient and have lower emissions on a per-kWh basis (Table 24).

Table 24. Estimated Stack Emission: Scenario 2

	Shortfall (MWh)	SO_2 (tons)	NO_2 (tons)	CO_2 (tons)	CO (tons)	TOG (tons)	ROG (tons)	PM10 (tons)
Baseline	--	53	557	9,070,258	3,116	413	116	262
Retrofitted Fossil Increase	295,826	0.6	4	123,873	31	5	2	3
Retrofitted Nuclear Increase	1,824,732	5	63	757,965	321	28	9	20
Net Increase	**--**	**11%**	**12%**	**10%**	**11%**	**8%**	**9%**	**9%**

Scenario 3: All fossil fuel units are repowered to combined-cycle systems with dry cooling. Nuclear units are retrofitted to wet cooling, with replacement generation provided by new combined-cycle units (Table 25).

Table 25. Estimated Stack Emission: Scenario 3

	Fuel Usage (MMBTU)	SO_2 (tons)	NO_2 (tons)	CO_2 (tons)	CO (tons)	TOG (tons)	ROG (tons)	PM10 (tons)
Baseline	151,648,525	53	557	9,070,258	3,116	413	116	262
Repowered Fossil [a]	118,351,861	43	402	7,030,961	2,104	280	104	267
Retrofitted Nuclear	12,760,349 [b]	5	63	757,965	321	28	9	20
Net Change	**-14%**	**-9%**	**-17%**	**-14%**	**-22%**	**-26%**	**-3%**	**10%**

Notes:
a. Based on average emission factors for new, dry-cooled combined-cycle units.
b. Fuel usage for retrofitted nuclear facilities refers to the additional fuel that would have to be consumed by a combined-cycle fossil unit to replace the generating shortfall from the nuclear facilities.

In each scenario, emission changes are driven by the large MWh shortfall that would result from retrofitting Diablo Canyon and SONGS to closed-cycle systems; these retrofits alone would account for 80-90% of any increase. Capacity utilization at the fossil-fueled units is not expected to increase.

4.5.2 *Wet Cooling Tower Emissions (Fine Particulate Matter)*

The principal air pollutant emitted directly from wet cooling towers is small particulate matter. Dissolved solids in the circulating water result in fine particulate emissions (PM10) when water droplets ejected from the tower evaporate before they reach the ground. PM10 is a significant concern throughout most of California with nearly all counties designated as non-attainment areas, including all counties in which coastal OTC facilities reside.

For power plants that undergo a retrofit with wet cooling towers, an important threshold is the emission of PM10. A cooling tower would increase a facility's cumulative PM10 emissions, although the increase would be based on the capacity utilization for the facility. The NSPS threshold for determining a significant net emissions increase is 15 tons per year. High-efficiency air pollution controls (drift eliminators) that minimize PM10 emissions from cooling towers are presently accepted as BACT for cooling towers (at 0.0005% efficiency). Even with these controls, however, the increased PM10 emissions at some facilities may be enough to trigger NSR for the entire facility. This would involve BACT or LAER evaluations of all emission sources at the plant as part of the permit modification process.

PM10 Calculation Methods

Total PM10 emissions can be conservatively estimated by assuming the full concentration of dissolved solids in any exiting water droplets will be converted to airborne PM10. This method, used by USEPA, discounts the possibility that some droplets do not evaporate prior to deposition on the ground and assumes that all particulate matter would be classified as PM10. Some studies have suggested that PM10 estimates made with these assumptions may exaggerate actual emission rates from cooling towers.[131]

An alternative calculation method indicates that, depending on the droplet size distribution of the drift, only a certain percentage of drift PM can be classified as PM10. 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 40% less than the USEPA method.[132] Essentially, as TDS concentrations increase, the proportion of droplets capable of producing PM10 decreases. Dissolved solids are more likely to result in large particulate matter that would not be classified as PM10.

PM10 Emissions

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

Table 26 shows estimated PM10 emissions for retrofitted facilities using the AP-42 (USEPA) method and the alternative method, which better approximates the conditions that would be found at California's coastal facilities using saltwater as the makeup water source. These estimates are calculated based on a facility's design capacity and 2006 net output.

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[131] Michelleti, W.C. "Atmospheric Emissions from Power Plant Cooling Towers." *CTI Journal.* Vol. 27, No 1. 2006.
[132] Joel Reisman and Gordon Frisbie. Calculating Realistic PM10 Emissions from Cooling Towers. Greystone Environmental Consultants. *Environmental Progress*, Volume 21, Issue 2.

Table 26. Estimated Wet Cooling Tower PM_{10} Emissions

	USEPA AP-42 Method		*Alternative Method*	
	Maximum Capacity (tons/year)	**2006 Output (tons/year)**	**Maximum Capacity (tons/year)**	**2006 Output (tons/year)**
Alamitos	460.38	45.38	23.02	2.27
Contra Costa	172.60	4.11	8.63	0.21
Diablo Canyon	992.67	951.10	49.63	47.56
El Segundo	151.54	15.95	7.58	0.80
Harbor	32.45	2.89	1.62	0.14
Haynes	342.78	74.05	17.14	3.70
Huntington Beach	193.31	28.77	9.67	1.44
Mandalay	96.31	7.99	4.82	0.40
Moss Landing	466.02	98.87	23.30	4.94
Ormond Beach	261.20	9.40	13.06	0.47
Pittsburg	184.68	11.65	9.23	0.58
SONGS	915.47	794.52	45.77	39.73
Scattergood	198.20	42.35	9.91	2.12
Total	**4467.61**	**2087.03**	**223.38**	**104.36**

4.5.3 *Air District Survey*

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

At the request of the State Water Board staff, the California Air Resources Board 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 South Coast Air Quality Management District 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 (construction generally is one to seven year process).

Mitigation Measures

Mitigation measures for stack emissions (except carbon dioxide) may include system controls to reduce criteria pollutant emission rates. These controls include low NOx burners, selective catalytic reduction, oxidizing catalysts, and wet or dry scrubbers. Mitigation may also be achieved by repowering older, less efficient units to more modern combined-cycle technologies that emit less pollution on a per-kWh basis. Mitigation for PM10 from wet cooling towers is achieved by incorporating high efficiency drift eliminators (0.0005%), which are currently considered BACT for this emission source.

Assessment

State Water Board staff cannot accurately assess air quality impacts related to criteria pollutants because it is difficult to estimate the method of compliance for each facility.

The NSPS threshold for determining a significant net emissions increase for PM10 is 15 tons per year. Based on calculations presented in Table 26 for the alternative method, only 5 of the 12 facilities considered for wet cooling tower retrofits would be subject to NSR.

4.6 GREENHOUSE GASES

General scientific consensus and increasing public awareness regarding global warming and climate change have placed new focus on the CEQA review process as a means to address the effects of greenhouse gas emissions from proposed projects on climate change.

Climate change refers to any significant change in measures of climate, such as average temperature, precipitation, or wind patterns over a period of time. Climate change may result from natural factors, natural processes, and human activities that change the composition of the atmosphere and alter the surface and features of the land. Significant changes in global climate patterns have recently been associated with global warming, an average increase in the temperature of the atmosphere near the Earth's surface, attributed to accumulation of greenhouse gas emissions in the atmosphere. Greenhouse gases trap heat in the atmosphere, which in turn heats the surface of the Earth. Some greenhouse gases occur naturally and are emitted to the atmosphere through natural processes, while others are created and emitted solely through human activities. The emission of greenhouse gases through the combustion of fossil fuels (i.e., fuels containing carbon) in conjunction with other human activities, appears to be closely associated with global warming.

State law defines greenhouse gases to include the following: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride (Health and Safety Code, §38505(g).) The most common greenhouse gases that results from human activity is carbon dioxide, followed by methane and nitrous oxide.

Senate Bill 97 (Chapter 185, Statutes of 2007) amends the CEQA statute to clearly establish that greenhouse gas emissions and the effects of these emissions are appropriate subjects for CEQA analysis. It directs the Office of Planning and Research to develop draft CEQA Guidelines "for the mitigation of greenhouse gas emissions or the effects of greenhouse gas emissions" by July 1, 2009 and directs the Natural Resources Agency to certify and adopt the CEQA Guidelines by January 1, 2010 (The Natural Resources Agency recently noticed its proposed amendments to the CEQA Guidelines related to greenhouse gas emissions http://ceres.ca.gov/ceqa/guidelines).

Implementation of the Policy may result in a net increase in the amount of carbon dioxide and nitrous oxide emissions for all OTC facilities combined. The worst case scenario (see Scenario 1 in Section 4.5) would have a 14% increase in carbon dioxide emissions and an 18% increase in nitrous oxide emissions (Table 23). Conversely, Scenario 3 in Section 4.5 would see a 14% decrease in carbon dioxide emissions and a 17% decrease in nitrous oxide emissions (Table 25). It is not known what steps individual power facilities will take to comply with the Policy. Staff expects that the actual net increase in greenhouse gas emissions will fall somewhere in between these extremes (0-5% net increase in greenhouse gas emissions). As such, staff has determined that there will be a less than significant impact to the environment.

4.7 NOISE

Title 4 of the California Code of Regulations establishes guidelines for evaluating the compatibility of various land uses as a function of community noise exposure. Cal-OSHA has promulgated Occupational Noise Exposure Regulations that set employee noise exposure limits.[133] In addition, local governments typically set community noise limits based on zoning classifications and existing uses. The Tetra Tech report investigated local noise ordinances when it evaluated closed-cycle wet cooling feasibility for the State's OTC facilities.

Noise impacts from wet cooling towers are a function of the large fans that are required to draw air up through the tower and the sound of water falling from a certain height. The level of noise at different receptors will depend on distance and the presence of interfering structures.

Mitigation Measures
Mitigation can be achieved by incorporating design elements that reduce ambient noise to acceptable levels. Gear box insulation and fan deck barrier walls can be installed to muffle fan noise, while ground level barrier walls can reduce falling water noise.

Assessment
Mitigation measures to control noise from wet cooling towers are readily available and can be easily installed, albeit at increased cost. The Tetra Tech report identified four facilities (Haynes, Alamitos, Scattergood, and Morro Bay) that would have to incorporate such measures in order to comply with local noise ordinances. Noise impacts at these facilities are considered to be Less than Significant with Mitigation; all others are considered to have no impact.

4.8 PUBLIC HEALTH

Cooling tower operation can theoretically contribute to public health risks, specifically *Legionella pneumophilia* (Legionnaire's Disease), if individuals come in contact with contaminated water that has been left stagnant or is insufficiently treated. Legionnaire's Disease can be a significant health risk, especially when contracted by individuals with compromised immune systems or existing respiratory ailments. Annual incidents are rare, however, with little evidence of a wide-ranging threat to public health from properly-maintained cooling towers.

Mitigation Measures
Pathogen control in cooling towers is already required by state and federal regulations and is addressed by incorporating sufficient biofouling treatment systems into the initial design and following proper maintenance and worker safety procedures.

Assessment
Impacts are less than significant with the required mitigation measures for all facilities.

4.9 WATER QUALITY

4.9.1 *Effluent Quality (Priority & Conventional Pollutants)*

Compliance alternatives for OTC power plants that would substantially change the characteristics of wastewater effluent include the installation of cooling towers (wet cooling

[133] CAL. CODE OF REG. Tit. 8, §§ 5095-5099.

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.

Most steam electric power plants in California discharge low volume, or in-plant, wastes along with the main condenser cooling water. These wastes, which can include boiler blowdown, treated sanitary waste, floor drains, laboratory drains, de-mineralizer regeneration waste and metal cleaning waste, among others, are significantly diluted when combined with the vastly larger volume of cooling water. Substantially reducing the cooling water-related discharge volume may alter the characteristics of the final discharge by increasing pollutant concentrations and possibly triggering concerns over whole effluent toxicity, but will also reduce any thermal discharge impacts

For marine dischargers currently regulated under the Ocean Plan or for facilities discharging to inland waters, estuaries or enclosed bays and regulated under a Basin Plan, the California Toxics Rule and the Policy for Implementation of Toxics Standards for Inland Surface Waters (SIP), new dilution models will likely need to be developed. If sufficient dilution is not available, additional treatment or alternative discharge methods may be required, such as the incorporation of submerged diffusers to reduce the thermal and high salinity plumes. For all facilities, cooling tower blowdown wastes are regulated by federal Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities.

EPA promulgated the current ELGs for the steam electric point source category in 1982. At the time, chromium and zinc compounds were commonly-used maintenance chemicals to control corrosion and fouling in cooling towers. USEPA retained a numeric effluent limitation for these pollutants out of concern that acceptable alternatives were not widely available. Technology advances and regulatory restrictions enacted since 1982 have largely eliminated the need to use chromium and zinc compounds as cooling tower maintenance chemicals. Furthermore, acceptable substitutes are more widely available and more effective when coupled with corrosion-resistant materials such as fiberglass-reinforced plastic, titanium, or stainless steel, which are the preferred design materials for saltwater applications. Despite these changes, ELGs remain an NPDES component and would require a retrofitted facility to demonstrate its compliance.

A facility retrofitted to closed-cycle wet cooling would theoretically continue to discharge low volume wastes (boiler blowdown, sanitary treatment wastes, etc.) at the same volume, but, without the benefit of dilution from once through cooling water volumes, might discharge some pollutants in higher concentrations in the final effluent. In other cases, low volume wastes are not at issue. Rather, the evaporating effects of a wet cooling tower can concentrate non-volatile pollutants to levels that would exceed water quality standards and lead to violations of effluent limitations contained in the SIP or Ocean Plan.

In general, coastal OTC facilities that withdraw water from the open ocean are not likely to experience any difficulties meeting Water Quality-Based Effluent Limitations when converting to closed-cycle wet cooling systems. A preliminary analysis of effluent data from El Segundo and SONGS showed that increased concentrations for metals would not exceed Ocean Plan requirements, although State Water Board staff notes that new dilution models that reflect the reduced discharge volume would need to be developed in order to accurately estimate compliance with new effluent limitations.

Facilities that withdraw water from enclosed bays and estuaries, however, may experience conflicts with effluent limitations as a retrofitted facility. Staff analyzed effluent data for an example facility to assess the whether this situation is possible.

LADWP's Haynes Generating Station, located in Long Beach, was selected as an example facility due to its overall size (current intake volume of 968 MGD) and its location. The facility withdraws water from the Alamitos Bay/Long Beach Marina via a man-made canal. The source water has known issues with several pollutants due to high recreational boat traffic in the marina and poor water circulation within the bay. The facility discharges to the San Gabriel River, an effluent-dominated stream during dry periods (together with AES's Alamitos Generating Station, located on the river's west bank). In addition, the Regional Water Board notified LADWP that the San Gabriel River had been reclassified from a marine water to an estuary, thus the SIP will govern effluent limitations for Haynes rather than the Ocean Plan.

Intake data was used from sampling events from 2003-2004, with the maximum detected value used for each constituent. If a constituent was not detected, it was assumed to not be present in the intake water. The maximum detected value for each detected constituent was concentrated by 50% to account for tower evaporation (1.5 cycles of concentration).

Low volume waste stream data was taken from monitoring events from 9/13/2000 – 5/7/2003. The maximum detected concentration was used, and multiplied by the maximum combined low volume waste stream flow, which was taken from the 2006 draft Haynes permit. Once the mass was obtained, it was divided by the new flow rate, which was calculated by adding in the estimated cooling tower blowdown flow (26,100 gpm) to the combined low volume waste stream flow. The result was a new, estimated concentration for priority pollutant constituents.

This estimated concentration was used as the maximum effluent concentration in a reasonable potential analysis. The results of the analysis indicated reasonable potential for arsenic, copper, nickel, and zinc. Effluent limitations were calculated for these constituents, and the feasibility to comply with limitations was determined by comparing the maximum effluent concentration (MEC) to the average monthly effluent limitation (AMEL) and the maximum daily effluent limitation (MDEL). These results are summarized in Table 27.

Table 27. Example Effluent Limitation Calculation

Parameter	AMEL	MDEL	MEC	Feasible?
Arsenic	29	59	67	No
Copper	2.9	5.8	14	No
Nickel	6.8	14	46	No
Zinc	47	95	217	No

Based on the RPA for revised effluent, and assuming other discharges continue normally, Haynes would have difficulty meeting SIP limitations for these four. It is noted, however, that Haynes may have difficulty meeting these limitations as an OTC facility due to the receiving water reclassification.

Mitigation Measures

Treatment systems are available that can remove metals from wastewaters, although cost may be significant for a facility that needs to treat several million gallons per day. Other measures include alternative discharge locations, zero liquid discharge, or an alternative water source to provide makeup water.

Assessment

Impacts are considered to be “Less than Significant” for Haynes, Alamitos, and Mandalay. Although these facilities may face difficulty meeting effluent limitations as a retrofitted facility, Staff did not consider these impacts significant because each facility is unlikely to meet effluent limitations as an OTC facility already; compliance with the proposed Policy does not cause the impact. No impact was determined at all other facilities.

Thermal Impacts
A significant benefit of wet cooling system retrofits, in addition to reduced impingement and entrainment, is the reduced impact on the receiving water resulting from elevated temperature waste discharges. California’s coastal facilities, many of which are 40 years or older, are currently regulated for thermal discharge under the Thermal Plan as existing sources for elevated temperature wastes. Permitted discharge temperatures are based on criteria that seek to protect designated beneficial uses and areas of special biological concern, and range as high as 100ºF in some cases. Thermal plumes can extend long distances from the discharge point and have far-reaching effects on the receiving water. Wet cooling towers, in addition to dramatically reducing the discharge volume and thermal plume, can be configured to discharge blowdown directly from the tower’s cold water basin, with a discharge temperature that more closely approximates the receiving water.

4.10 UTILITIES AND SERVICE SYSTEMS

California’s once-through cooled power plants deliver energy to critical points in California’s electricity grid, especially within the state’s largest Local Reliability Areas, where the ability to import energy is limited and the local utility must instead rely on local power plants to maintain electric service reliability. Some OTC plants are needed year-round to provide reliability service within Local Reliability Areas because no other resource is available to supply that service. Others are needed only during periods of very high demand, such as during a summer heat wave, and are idled for much of the rest of the year. Three other OTC plants – the two nuclear plants and the newest gas-fired plant – are located along key intra-regional transmission lines, playing a significant role in reducing congestion along those vital transmission paths.

The nuclear plants provide base-load service, operating at or near maximum power levels 24 hours per day, shutting down only for maintenance and refueling. Together, the two nuclear plants provided about 13% of the state’s total electric energy needs in 2005, and about 63% of the total energy produced by all the OTC plants. The gas-fired plants generally operate as load-followers, operating at low power levels in the morning and gradually ramping power levels up to match demand during the day, and reversing the process in the late afternoon into evening. Power levels at the gas-fired OTC plants generally match their age, with the newer, more efficient combined-cycle plants operating at higher levels than the older, less-efficient steam boiler plants. The exceptions are those older plants located in Local Reliability Areas, where no other resource is available to serve local load.

Effects on Electric Reliability
In general, generation at most of the older OTC plants has trended downward in recent years because their relative age and inefficiency has made them less competitive with newer generation. Already faced with this competitive disadvantage, several of the owners of these plants have stated that the Board’s new rules could force the retirement of several generating units, especially those already on the verge of financial non-viability, possibly posing a threat to electric system reliability. Though retirement presents the greatest threat to electric reliability, compliance with the new rules also presents reliability concerns, including the potential reduced

net generation from OTC plants after they convert to wet cooling, and the unavailability of the nuclear plants while they shut down to convert.

The Jones and Stokes report[134] examined those threats using a computer modeling effort to simulate the potential economic impacts of the proposed Policy and the resulting reliability impacts that could occur when and if OTC generating units are retired. The modeling effort simulated effects on California's electric power grid caused by retirement and/or de-rating of OTC plants, identifying and quantifying transmission system segment overloads that could occur following OTC plant retirements. The modeling effort also showed how costs to the ratepayer could change depending on how and when the proposed Policy is enacted, and produced estimates of the net changes in power plant emissions caused by the new policy.

Analysis of the modeling results, as well as of other studies and sources of information, shows that though certain trends are evident, predicting the future operation of any one plant is conjecture at best. Faced with tough economic decisions, plant owners could choose to retrofit their OTC plants with an alternative form of cooling, repower their plants by essentially building a new plant using alternative cooling and then decommissioning the old one, or shut the plant down, either permanently and convert to another use, or temporarily while waiting for more favorable economics for repowering or retrofitting.

The greatest threat to electric system reliability would occur in the unlikely event that OTC plant owners choose en masse to retire their plants without sufficient time for the industry to assess the impact of those retirements and plan accordingly. The modeling examined a wide range of retirements and time frames for policy enactment. The most severe effects were found in the extreme cases of all OTC plants retiring in 2009, which would require no less than a WWII-like mobilization effort to locate and site combustion turbines, the only type of plant that could be placed on-line in such a short time-frame, while also enacting emergency conservation measures. However, the modeling also showed that given sufficient time to react, the electric industry could likely tolerate and compensate for mass OTC plant retirement at relatively modest costs to the ratepayer.

In all but one of the cases examined in the 2015 time frame, when many other currently planned power plants throughout the Western U.S. and Canada will be on-line, the modeling showed that OTC plant retirements could be compensated for solely through transmission upgrades. The one exception was in the extremely unlikely event that all OTC plants are permanently retired, including the two nuclear plants, which would require construction of new generating plants along with substantial transmission upgrades, costing ratepayers as much as $11 billion. In other words, under all but the most extreme scenarios, more than enough power plants are expected to be operating in 2015 to more than compensate for any or all OTC plant retirements, with a projected 28% reserve margin of supply over demand in the western half of North America. The key will be ensuring the transmission system is capable of delivering energy from those plants to the loads presently served by OTC plants.

The Jones and Stokes report shows that while the proposed 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. The general consensus of the energy industry is that five years is needed to plan, site, permit, and construct a new major power plant, and seven years is needed for a new major transmission

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[134] ICF Jones and Stokes, Global Energy Decisions, and Matt Trask. *Electric Grid Reliability Impacts from Regulation of Once-Through Cooling in California*. April 2008.

line. However, the vast majority of the transmission upgrades identified in the analysis to compensate for OTC plant retirements are relative modest, requiring only one to three years to construct and place in-service. Because 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, according to the Jones and Stokes report. More challenging, however, is planning and building the needed out-of-state transmission infrastructure through the inter-regional planning process, in which California has little control over the outcome, to compensate for the extreme case of all OTC plants retiring, including the nuclear units.

Wide Area Environmental Effects

The effects of the proposed Policy on net power plant sector emissions across the western half of North America (from British Columbia and Alberta to Baja California and the 14 U.S. states in between) would be significant only if all OTC plants (including the nuclear units) are retired, which would result in a modest one to 2% increase in carbon dioxide emissions sector-wide. All other scenarios examined showed either no change or a modest reduction in net carbon dioxide emissions because the plants replacing the retired OTC plants in general would be considerably more efficient. Other types of emissions from the power sector, including NOx, SOx and mercury, showed virtually no change regardless of how many OTC plants are retired.

The indirect environmental impacts that could occur due to the proposed Policy would be directly related to the amount of new infrastructure constructed to compensate for any retirements. Depending on how and when the proposed Policy was enacted, the infrastructure needed could range from quite modest to extremely vast, from as many as 800 new small power plants in the state at a cost of well over $10 billion if all OTC plants are retired in 2009, to as little as 135 million dollars in modest, low-impact transmission upgrades in the still unlikely event that all but the nuclear plants are retired in 2015.

All such infrastructure development would be subject to environmental and technical analyses and approvals. With the exception of a few land use impacts related to zoning issues, power plant construction in California in recent years resulted in no significant, unmitigated impacts to public safety and the environment. And though major transmission line projects often result in unmitigated impacts to visual resources, especially those through national forest and park lands, the vast majority of the upgrades identified in the modeling effort would have no impacts, even during construction. Therefore, with proper planning and oversight, the proposed Policy is not likely to result in significant cumulative impacts to public safety and the environment, though one area of concern is cumulative land use impacts because of zoning issues. The most realistic scenarios examined, in which some OTC plants would be retired while others repower or convert their cooling systems, showed potential for significant benefits to the environment because the overall power sector would be more efficient and produce fewer emissions, and because marine ecosystem impacts caused by use of OTC technology would be greatly reduced.

Mitigation Measures

Disruptions to utility services and grid reliability are most effectively mitigated by establishing a statewide policy that includes provisions to coordinate implementation among the Regional Water Boards and consult with the State's energy agencies.

Assessment

Impacts are considered "Less than Significant" with mitigation, as described above.

4.11 GROWTH-INDUCING IMPACTS

The CEQA Guidelines (Title 14, Cal. Code of Reg., 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. (Title 14, Cal. Code of Reg., §15126.2(d))

Assessment
Implementation of the proposed Policy will not result in an increase in energy generation and is, therefore, not expected to induce additional growth. No impacts are expected.

4.12 CUMULATIVE AND LONG-TERM 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. [135]

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.

Assessment
Implementation of the proposed Policy will not result in cumulative impacts.

[135] CAL. CODE OF REG., Title 14, §15355

5.0 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 have re-powered or 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 closed-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 evaluated each facility with respect to technologies that can achieve a 90–95% reduction of IM/E impacts as discussed in the 2006 Ocean Protection Council 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).

Table 28 presents a 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, operation and maintenance, and energy penalty estimates. All annual costs are amortized over 20 years at 7%.

Table 28. Annual Cost Summary – Facility[136]

[136] 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.

Facility	Category[(a)]	20-year annualized cost [(b)(c)] (dollars)	Rated Capacity (GWh)[(g)]	Cost Per MWh (dollars/ MWh)[(h)]	2006 Net Output (GWh)	Cost (dollars /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
SONGS [(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**

Notes:
(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, SONGS: $595 million, Haynes: $5 million, and 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.
(g) GWh = gigawatt hour
(h) 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%.

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. It may be apparently more economical for these older generating units to follow the leads of the Long Beach, Humboldt Bay, El Segundo, and Encina generating stations, which look to eliminate or greatly reduce OTC 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 IM/E reduction requirements.

The Jones and Stokes 2008 Report provides a programmatic evaluation of potential impacts to the electric system reliability. According to this grid modeling effort, overall costs of a statewide policy to replace OTC could range from as little as around $100 million (with a sufficient planning horizon) to as much as $11 billion (immediate and complete shutdown of all OTC plants). Obviously it depends 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 costly 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.

The Jones and Stokes Report states that the greatest threat to electric system reliability would occur in the extremely unlikely event of OTC plant owners choosing en masse to retire their plants without sufficient time for the industry to assess the impact of those retirements and plan accordingly. The Policy has been crafted to directly avoid this kind of scenario. This would have happened in the extreme cases of all OTC plants retiring in 2009 (or effectively as soon as the policy was approved), which would require no less than a WWII-like mobilization effort to locate and site combustion turbines, the only type of plant that could be placed on-line in such a short time-frame, while also enacting emergency conservation measures. It is this case that would require immediate construction of new generating plants along with substantial transmission upgrades, costing ratepayers as much as $11 billion.

However, the report modeling also showed that given sufficient time to react, the electric industry could likely tolerate and compensate for mass OTC plant retirement at relatively modest costs to the ratepayer. The report concludes that under all but the most extreme scenarios, more than enough power plants are expected to be operating in 2015 to more than compensate for any or all OTC plant retirements, with a projected 28% reserve margin of supply over demand in the Western half of North America. The key will be ensuring the transmission system is capable of delivering power from those plants to the loads presently served by OTC plants. The Report's projected costs for these transmission upgrades range from about $314 million up to about $1 billion, with a significant part of that occurring outside of California. Many transmission upgrades are already on the drawing board, as they are necessary for the continuing evolution of California's energy system and would occur even in the absence of the OTC policy requirements.

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California Energy Commission (CEC). *Issues and Environmental Impacts Associated with Once-Through Cooling at California's Coastal Power Plants.* CEC-700-2005-013. June 2005.

The purpose of this California Energy Commission (Energy Commission) staff report is to assess issues associated with once-through cooling impacts in the context of growing scientific and public policy concerns about the viability of California's coastal bay and estuarine ecosystems. California marine and estuarine environments are in decline and the once-through cooling systems of coastal power plants are contributing to the degradation of our coastal waters. Over the past several years, the Energy Commission has reviewed five coastal power plant applications and been faced with the challenge of how to determine the impacts of proposed new or repowered power plants that use once-through cooling and what should be done to mitigate the impacts. Given the widespread public and government agency concerns about the impacts to coastal ecosystems from California's coastal power plants that use once-through cooling and the difficulty in determining the economic and ecological costs of these systems, the Energy Commission may want to consider potential policy options to address these issues.

California Energy Commission (CEC) and Electric Power Research Institute (EPRI). *Comparison of Alternate Cooling Technologies for California Power Plants Economic, Environmental and Other Tradeoffs*. 500-02-079F. Sacramento, CA. 2002.

This study defines, explains, and documents the cost, performance, and environmental impacts of both wet and dry cooling systems. A survey of the cooling system literature is provided in an annotated bibliography and summarized in the body of the report. Conceptual designs are developed for wet and dry cooling systems as applied to a new, gas-fired, combined-cycle 500- MW plant (170 MW produced by the steam turbine) at four sites chosen to be representative of conditions in California. The initial capital costs range from $2.7 to $4.1 million for wet systems using mechanical-draft wet cooling towers with surface steam condensers and from $18 to $47 million for dry systems using air-cooled condensers.

Cooling system power requirements for dry systems are four to six times those for wet systems. Dry systems, which are limited by the ambient dry bulb temperature, cannot achieve as low a turbine back pressure as wet systems, which are limited by the ambient wet bulb. Therefore, heat rate penalties and capacity limitations are incurred at some sites depending on local meteorology. A methodology is developed and illustrated that accounts for these several components of cost and performance penalties in selecting an optimized design for a specific site.

A brief review is given of some advanced cooling system technologies currently in development, highlighting an evaporative condenser system with a water-conserving mode that halves the consumptive water use of a conventional wet system. In addition, current research in the power plant cooling field is reviewed with particular attention to concepts for enhancing the performance of dry systems during the peak period (the hottest hours of the year).

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Steam electric power plants and other industrial facilities that withdraw cooling water from surface water bodies are regulated in the United States under §*316(b) of the Clean Water Act of 1972. Of the industries regulated under* §*316(b), steam electric power plants represent the largest cooling water volumes with some large plant withdrawals exceeding 2 BGD. Environmental effects of cooling water withdrawal result from the impingement of larger organisms on screens that block material from entering the cooling water system and the entrainment of smaller organisms into and through the system. This paper focuses on methods for assessing entrainment effects (not impingement), and specifically, entrainment effects on ichthyoplankton. This report describes three studies that assessed entrainment at coastal power plants in California and discusses some of the considerations for the proper design and analysis of entrainment studies.*

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A significant portion of California's generation capacity, approximately 45%, is represented by facilities located along the state's coast and estuaries that use once□*through cooling technology, where the ocean water is passed by the condenser and then discharged back into a water body. This cooling technology withdraws* *approximately 17 BGD when all plants using this technology are fully operational. Although some of these facilities have been operating since the 1950s, a scientific understanding of the ecological effects of the use of once-through cooling is quite limited. The California Energy Commission is funding research to understand and provide tools to minimize the effects of once-through cooling on California's coastal resources. In this study, the authors reviewed existing literature on the effects of once-through cooling, identified areas where knowledge gaps exist, and convened an advisory group to address those gaps. The areas of concern that were identified are the ability to: measure effects, determine the affected area and related oceanography, identify entrained species, determine useful technology to implement for reducing entrainment, and determine when mitigation is useful or successful. This information will be used to help identify once-through cooling research that should be funded in the future.*

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The 2005 Environmental Performance Report provides an analytical basis for policy discussions and options that may be incorporated into the Integrated Energy Policy Report. Its findings will be presented at a series of public workshops on June 27 and 28, 2005. Interested parties are encouraged to review this staff report and to provide comments relating both to the report's content and to possible policy options that may follow from the environmental status and trends discussed in the report.

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Discussion of the use of fiberglass for structural component of wet cooling towers. A brief review of the types of power plant cooling systems is given. The benefits of the choice of fiberglass for tower construction along with the implications of this choice for tower structural design are presented. Some practical observations based on experience with industrial process applications is given. Benefits are in low cost, low maintenance and ease of construction.

ICF Jones and Stokes, Global Energy Decisions, and Matt Trask. *Electric Grid Reliability Impacts from Regulation of Once-Through Cooling in California.* April 2008.

This study examines the general energy implications of the State Water Resource Control Board's pending policy decision concerning use of seawater at coastal power plants. Discusses various implementation scenarios that could conceivably result and models economic, environmental and grid reliability issues that would arise from each.

Lawson, Dan. National Marine Fisheries Service. Personal Communication. 2009.

Lawler, Matusky & Skelly Engineers. *Lovett 2000 Report.* Prepared for Orange and Rockland Utilities, Inc. 2000.

Status report of pilot study program from an aquatic filtration barrier at the Lovett Generating Station on the Hudson River in NY. Provides overall effectiveness estimates as well as maintenance issues and deployment concerns.

Liegois, W.A., P.E. and T.A. Brown, P.E. *Optimizing Condenser Water Flow Rates.*

Most chillers are designed for a 10 degree temperature rise across the condenser unit. This paper explores opportunities for the design engineer to reduce both operating costs and first costs by designing for higher temperature changes and their resultant lower flow rates. Other advantages include smaller footprints for cooling towers thus saving valuable space on the site or on the building roof.

Lindahl, P. and R. W. Jameson. *Plume Abatement and Water Conservation with the Wet/Dry Cooling Tower.* CTI Journal 14. 1993.

Discussion of hybrid wet/dry cooling towers for both plume abatement and water conservation. Excellent descriptions of the configuration and thermodynamic operating principles of the several tower types are given. Attention is given to the selection of the design point for real applications. No cost information is included.

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Maulbetsch, J. S., and M. N. DiFilippo. *Cost and Value of Water Use at Combined-Cycle Power Plants.* California Energy Commission, PIER Energy-Related Environmental Research. 500-2006-034. 2006.

This study compared water requirements, plant and cooling system capital and operating costs, and plant output and efficiency between plants equipped with wet and dry cooling. Comparisons were made for 500 megawatt, gas-fired, combined-cycle power plants at four sites, typical of environmental conditions in California. A plant design was generated for each site/plant/cooling system combination. The total plant costs and selected individual component costs for each design were determined.

Researchers calculated performance characteristics—including net plant output, heat rate, water consumption, and operating power requirements.

Results of the analysis include:
• the use of dry cooling reduces plant water requirements by approximately 2,000 to 2,500 acre-feet per year,
• The associated costs are:
− increased plant capital cost of approximately $8 million to $27 million, or about 5% to 15% of the total plant cost,
− potential reduction of energy production by about 13,000–56,000 megawatt hours (MWh) per year (1% to 2% of the total),
− capacity reduction on hot days of 13 to 23 MW (4% to 6% of total), and − potential annual revenue reduction of about $1.5 to $3.0 million (1% to 2% of total).

Mirsky, G. and J. Bauthier. *Cooling Towers: New Developments for New Requirements.* TR-104867. EPRI. Palo Alto, CA. 1994.

Addresses the design of cooling towers for combined-cycle power plants. The discussion is organized around three sets of requirements: water use and pollution, noise and visibility. Particular attention is given to determining the cooling tower requirements for the special case of a combined-cycle power plant where the steam part of the cycle accounts for only about 1/3 of the plant output but for which the cycle efficiency may be fairly poor compared to standalone steam plants. Order of magnitude cost comparisons are provided based on the authors' corporate experience.

Michelleti, W.C. *Atmospheric Emissions from Power Plant Cooling Towers.* CTI Journal. Vol. 27, No 1. 2006.

Journal article discussing methods used to estimate fine particulate matter emissions from wet cooling towers, including most conservative EPA method (AP-42). Describes how standard method likely overestimates fine particulate matter by an order of magnitude and discusses alternative methods that are more appropriate for cooling towers in salt water environments.

Mirant Delta, LLC. *Clean Water Act §316(b) Proposal for Information Collection for Mirant's Contra Costa Power Plant.* 2006. Antioch, CA.

Mirant Delta, LLC, *Entrainment and Impingement Monitoring Plan for IEP, Annual Report Nov. 2007- Oct. 2008 Contra Costa and Pittsburg Power Plants,* July 2009

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Mussalli, Y.G., E.P Taft III, and J. Larson. *Offshore water intakes designed to protect fish.* 1980. Journal of the Hydraulics Division Proceedings of the American Society of Civil Engineers, Vol. 106 (1980): 1885–1901.

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Puder, Markus G. and John A. Veil. *Summary Data on Cooling Water Use at Utilities and Nonutilities*. US DOE, Argonne National Laboratory. 1999.

Compiled data describing cooling water usage and system designs at US power plants. Develops limited cost estimates for retrofitting existing facilities.

Public Service Company of New Hampshire, et al. Seabrook Station, Units 1 and 2, (June 10,1977 Decision of the Administrator) Case No. 76-7, 1977 WL 22370 (USEPA)

Reisman, Joel and Frisbie, Gordon. *Calculating Realistic PM10 Emissions from Cooling Towers.* Greystone Environmental Consultants. Environmental Progress, Volume 21, Issue 2.

Discussion of an alternative method used to calculate fine particulate matter emissions from wet cooling towers. Method is based on the distribution of water droplet sizes from a tower fitted with high efficiency drift eliminators and the assumption that high dissolved solids levels translate to larger particulate matter upon evaporation. High salinity drift produces more particulate matter overall, but less of it is classified as fine particulate than from a comparable fresh water tower. Estimates of actual PM10 emissions range as low as 5 to 10% of estimates using EPA method (AP-42).

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Schimmoller, Brian. *Wet, Dry and In Between*. Power Engineering. March 2007.

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Southern California Edison. Comment Letter – Once-Through Cooling Policy. May 20, 2008.

Southern California Edison. *Proposal for Information Collection—San Onofre Nuclear Generating Station.* San Clemente, CA. October 2005.

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